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December 23, 2003

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HAND DELIVERED

Thomas M. Dorman
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

RECEIVED
DEC 23 2003
PUBLIC SERVICE COMMISSION

RE: ***P.S.C. Case No. 2002-00475***

Dear Mr. Dorman:

Please find enclosed and accept for filing the original and ten copies of the Cost-Benefit Study performed by Cambridge Energy Research Associates, Inc. (CERA) and the testimony of J. Craig Baker and Hoff Stauffer. By copy of this letter, I am delivering a copy of the testimony and study to the persons listed below.

Sincerely yours,

STITES & HARBISON PLLC

Mark R. Overstreet

Enclosures
cc: David F. Boehm
Elizabeth E. Blackford
M. Byran Little
Brent L. Caldwell

KE057.KE157:10341.1:FRANKFORT

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

RECEIVED
DEC 2 3 2003
PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY POWER COMPANY	)
d/b/a AMERICAN ELECTRIC POWER, FOR	)
APPROVAL, TO THE EXTENT NECESSARY,	)
TO TRANSFER FUNCTIONAL CONTROL OF	)CASE NO. 2002-00475
TRANSMISSION FACILITIES LOCATED IN	)
KENTUCKY TO PJM INTERCONNECTION, L.L.C.	)
PURSUANT TO KRS 278.218	)

RESPONSES OF KENTUCKY POWER

D/B/A

AMERICAN ELECTRIC POWER

December 23, 2003

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

RECEIVED

DEC 23 2003

PUBLIC SERVICE COMMISSION

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APPLICATION OF KENTUCKY POWER COMPANY	)
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KENTUCKY TO PJM INTERCONNECTION, L.L.C.	)
PURSUANT TO KRS 278.218	)

DIRECT TESTIMONY AND EXHIBITS ON REHEARING

OF

J. CRAIG BAKER

December 23, 2003

DIRECT TESTIMONY ON REHEARING OF
J. CRAIG BAKER
FOR KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
CASE NO. 2002-00475

Q. Please state your name and business address.

A. My name is J. Craig Baker. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. Are you the same J. Craig Baker who filed testimony earlier in this proceeding?

A. Yes, I am.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, in accordance with the Commission's August 25, 2003 Order in this case, a Kentucky Power Company-specific cost/benefit analysis supporting the Company's application for authority to transfer functional control of its transmission facilities (along with those of the other AEP east operating companies) to PJM Interconnection LLC ("PJM"), an RTO approved by the Federal Energy Regulatory Commission ("FERC"), and to present other testimony on the issues set forth in the Company's August 6, 2003 Petition for Rehearing.

The centerpiece of the cost/benefit analysis is a simulated dispatch analysis conducted at American Electric Power's ("AEP") request by Cambridge Energy Research Associates ("CERA") that analyzes the effects of system operational changes associated with AEP's planned participation in PJM. Mr. Hoff Stauffer of CERA is presenting testimony and a report describing that analysis. My testimony describes the data that

AEP provided to CERA as inputs to CERA's analysis, and describes how AEP used CERA's analysis, and projected PJM costs, to arrive at a cost/benefit summary for Kentucky Power for the study period, 2004 through 2008. I also describe how these benefits will flow through to Kentucky Power customers.

Finally, I will provide testimony on the following issues that the Company raised on rehearing: 1) whether there are transmission flows and redispatch that would occur in connection with PJM membership that would result in significant unhedged congestion costs to Kentucky Power; 2) whether there are benefits associated with enhancement of reliability as a PJM member; and 3) whether the Commission's approval of the Company's participation in PJM would require the Commission to acquiesce in violation of KRS Section 278.214.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following Exhibits, which were prepared by me or under my direction and supervision.

Exhibit JCB-1 – Kentucky Power Company Estimated Net Benefits of Joining PJM 2004-2008

Exhibit JCB-2 – AEP System-Eastern Portion Estimated Net Benefits of Joining PJM 2004-2008

Exhibit JCB-3 – Calculation of Forecasted PJM Administration Charges 2004-2008

Exhibit JCB-4 – Kentucky Power Company Estimated Net Benefits of Limited AEP Participation in PJM 2004-2008

Exhibit JCB-5 - AEP System – Eastern Portion Estimated Net Benefits of Limited AEP Participation in PJM 2004-2008

Exhibit JCB-6- Kentucky Power Company – Net Merger Savings Credit

BACKGROUND

Q. What is the background of your testimony?

A. Kentucky Power and the other AEP operating companies in the AEP east transmission pricing zone ("east zone") are subject to a FERC merger condition requiring participation in an RTO. On December 19, 2002, Kentucky Power filed in this case an application for approval, to the extent necessary, to transfer functional control of transmission facilities located in Kentucky to PJM. The application and supporting materials described quantifiable and non-quantifiable benefits that would result from AEP's participation in PJM. Discovery was conducted and a hearing was held on the Company's application, and on July 17, 2003, the Commission issued an order denying the application. The Commission found that the Company had failed to demonstrate that its participation in PJM would produce net benefits to Kentucky retail electric customers. Among other things, the Commission based its decision on the Company's failure to present a company-specific cost/benefit analysis.

On August 6, 2003, Kentucky Power filed a Petition for Rehearing, raising various evidentiary and legal challenges to the Commission's order, including that KRS 278.218 does not require the filing of a cost/benefit analysis. Nevertheless, the Company offered to prepare and present company-specific cost/benefit information, and requested rehearing for the limited purpose of presenting such evidence. PJM, which had also intervened and participated in the hearings, also sought rehearing.

On August 25, 2003, the Commission issued an order granting rehearing to "provide reasonable time to Kentucky Power and PJM to file a Kentucky Power-specific cost/benefit analysis and provide additional testimony on the issues set forth in their respective petitions for rehearing." (Order, p. 5). Subsequently, procedures were agreed upon which called for Kentucky Power to file its cost/benefit analysis in December, 2003, and for discovery and hearings to follow. Kentucky Power's testimony and the accompanying cost/benefit analysis are being filed in accordance with that agreed-upon procedure.

Q. Have there been significant developments at FERC regarding AEP's planned participation in PJM since the original hearings in this case?

A. Yes. First, on November 17, 2003, FERC issued two orders eliminating out-and-through rates for transmission transactions within the area formed by PJM, Midwest ISO ("MISO") and the former Alliance companies, including AEP. FERC required these rates to be replaced by a Seams Elimination Charge Adjustment ("SECA") paid by loads in the affected area.

Second, on November 26, 2003, FERC issued an order making certain initial findings and proposing to exempt AEP from the Kentucky law requiring this Commission's approval of Kentucky Power's participation in PJM, and similar laws in Virginia. FERC preliminarily found that Kentucky Power and the other companies in AEP's east zone must join PJM by October 1, 2004. Proceedings are now underway in that case.

COST/BENEFIT STUDY

A. Study Approach

Q. Please describe the study methodology used to perform the cost/benefit study?

A. In order to quantify and demonstrate the likely economic cost/benefit to AEP's customers of joining PJM, AEP with the help of CERA conducted a study for the five-year period 2004-2008. For this purpose, CERA conducted certain market analyses to assess the effects associated with potential changes in the dispatch of AEP generation as a result of integration into the PJM markets as well as from elimination of out-and-through transmission service charges.

CERA used proprietary databases along with the General Electric Multi-Area Production Simulation ("GE-MAPS") software as the primary analytical tool in evaluating the system-operation related effects of joining PJM. AEP's east zone was modeled on an integrated basis. The analysis simulated a security-constrained economic dispatch for the PJM/MISO regions and beyond using the production cost simulation model for generators as well as detailed transmission network representation for the Eastern Interconnection.

As mentioned in CERA's report, CERA performed an analysis for three discrete years - 2004, 2006, and 2008. These three year study results were linearly interpolated for the remaining two years to complete the five-year study.

AEP then developed RTO participation cases by performing post-processing analyses of the applicable CERA results. The applicable CERA scenario analysis was augmented to include PJM administrative costs and certain avoided costs, to determine the overall costs and benefits for Kentucky Power.

Q. Please describe the scenarios CERA analyzed as input for the various cost/benefit study cases.

A. For the 2004-2008 five-year period, CERA examined two scenarios: A) One scenario in which out-and-through rates were assumed to be eliminated within the PJM/MISO footprint with a constrained economic dispatch of the expanded PJM/MISO area region and other regions, and B) another scenario in which existing out-and-through rates were assumed for AEP to remain in effect and existing dispatch regions were simulated to remain in place. These two scenarios were then used to assess the impact of AEP joining PJM through the development of cases that fully reflect the cost/benefits of participation compared to the situation that exists today. In the scenario in which out-and-through transmission rates were assumed to be eliminated, these rates were assumed to be eliminated for the entire PJM/ MISO footprint including those of Commonwealth Edison ("ComEd"), Dayton Power & Light ("DP&L") and Dominion Virginia Power ("DVP").

Q. Why does Scenario B assume the existence of out-and-through rates, given the FERC's November 17, 2003 Order eliminating those rates which you have described earlier?

A. Out-and-through rates exist today, and the FERC's November 17, 2003 Order has been challenged in requests for rehearing and in court. Moreover, FERC's order, I believe, represented an effort by FERC to advance some of the effects that would come with AEP's and others' integration into RTOs. The order can thus be seen as an interim step toward AEP's participation in PJM, such that the existence of out-and-through rates is a proper assumption for a business as usual case.

Q. Please describe the cost/benefit cases that you developed utilizing the input provided from the CERA scenarios.

A. From the input provided by the CERA scenarios and the post-processing input items, I developed two complete cases, with a third case (Case IA) that is a variation of one of the original two cases. These cases can be summarized as follows:

Case I: "AEP In PJM Case"

This case assumes that AEP has joined the PJM RTO and is fully participating in the PJM markets. The case utilizes CERA Scenario A described above. In this case, AEP would participate in the PJM market as well as in the Financial Transmission Right ("FTR") process, and incur potential congestion costs/benefits. Additionally, because this case assumes full participation in the PJM RTO, AEP would incur the full PJM administration charge allocation.

Case IA: "Limited AEP Participation in PJM"

This case assumes AEP's entry into PJM on a limited basis to provide FERC Order 2000 functions, such as Open Access Same-Time Information System (OASIS) administration, market monitoring, reliability coordination, and regional planning. This case does not assume AEP's participation in PJM's voluntary spot markets or locational marginal price ("LMP") congestion management program. However, PJM would have functional control of AEP's Eastern transmission network. Case IA also assumes elimination of out-and-through rates in the MISO/PJM footprint, which from a modeling perspective is equivalent to CERA Scenario A described above. It recognizes that the elimination of out-and-through rates would occur even under this case. The only significant differences between Case I and Case IA are the reduced level of administrative charges allocable to AEP and the absence of net FTR revenues. Case IA will be dealt with as a variation of Case I in my testimony with the reduced PJM administration costs and elimination of net FTR revenues.

Case II: "AEP Stand-Alone"

This case basically assumes circumstances as they are today with AEP not joining or participating in PJM. It utilizes CERA Scenario B as input in which out-and-through rates are assumed to still exist and existing control area dispatch regions are assumed to remain in place. Additionally, it assumes that AEP would continue to outsource certain transmission related functions such as OASIS administration functions and reliability coordinator functions as well as market monitoring.

Case II is a "business as usual" case that, for analytical purposes, provides the base case from which cost and benefit changes associated with PJM's participation (either on a full basis as in Case I or a more limited basis as in Case IA) can be identified.

Q. What data inputs did AEP provide to CERA for its analysis?

A. AEP provided pertinent data to CERA including key load and price parameters, in order to enable CERA to simulate the operation of the AEP System. Specifically, AEP provided CERA with: 1) AEP's internal load forecast; 2) the projected fuel data for 2004, 2006 and 2008; 3) the projected SO_2 and NO_X market prices for 2004, 2006, and 2008; 4) the emission controls, in-place and projected, for the AEP generating units; 5) expected conventional hydro generation levels based on historical experience; and 6) modeling information for the Smith Mountain Pumped Storage Project. This AEP-specific information was provided to CERA as input and used in combination with CERA's own data and its modeling tools to perform the scenario analyses.

Q. Please summarize the results of CERA's study.

A. The five-year CERA study primarily focused on likely short-run costs and benefits associated with the potential changes in the dispatch of AEP-east generation as a result of integration into the PJM markets and elimination of the out-and-through rates. In addition, the study also assessed other subjective benefits of joining PJM, such as, reliability enhancements, market efficiency, resource adequacy, and benefits of regional planning.

The CERA study results reveal that the majority of the benefits derived from joining PJM are due to the elimination of the out-and-through rates in the MISO/PJM footprint. The benefits associated with the potential changes in the dispatch of AEP-east generation as a result of PJM's market efficiencies are not as significant because AEP's low cost generation is nearly fully committed and dispatched to meet native load and system sales opportunities in today's non-RTO environment.

The CERA study results also reveal that the utilities to the east of the AEP system, such as DVP and existing PJM members, would benefit from AEP's participation in PJM, as AEP's low-cost generation would displace the high cost generation in those regions. AEP system reliability would improve, especially in the southeast portion in West Virginia, Virginia, and Kentucky. Other benefits identified by CERA include market efficiency and the benefits associated with regional planning.

Q. What post-processing steps did AEP perform using CERA's results?

A. The post-processing steps included: 1) annualizing CERA's hourly production cost simulation study results which were developed for the entire AEP east zone, 2) adding projected PJM administrative fees, and 3) recognizing avoided contract costs for certain functions that would be assumed by PJM. This resulted in a summary of the costs and benefits for the AEP east zone. The net benefits were then allocated to each of the east zone operating companies. The results in the Kentucky Power Company-specific cost/benefit summary are shown on Exhibit JCB-1. Exhibit JCB-2 provides the corresponding information for the AEP System as a whole.

B. <u>Description of Costs and Benefits</u>

Q. Please describe the types of costs and benefits shown in your cases.

A. The benefits fall into three categories: 1) Off-System Sales Profits; 2) Net FTR Revenues; and 3) Avoided Contract Costs. The only costs are the PJM administrative costs.

Q. Please explain the benefits associated with increased off-system sales profits.

A. Off-system sales are wholesale sales sourced from AEP generating units. Off-system sales occur when the market price for available energy exceeds AEP's variable cost to produce that energy. Profits from off-system sales are shared among the operating companies on an MLR basis. In Kentucky, half of these profits above a base level are automatically shared with customers. The CERA analysis indicates that in Case I, AEP's off-system sales profits would increase because increased supplies of its low-cost energy would be economically available to displace higher cost generation, mainly in the East. AEP's lowest cost generation would still be available to serve native load, but its higher cost generation, which is assigned to off-system sales, would still be lower cost than some generation in the East, and therefore would displace that generation.

Q. Please explain the benefit associated with net FTR revenues.

A. This benefit represents expected FTR revenue in excess of congestion costs. Congestion costs occur when a lower cost generation supply cannot be delivered to the load location due to transmission constraints. Congestion costs thus represent the increased cost of serving load during congestion conditions compared to the absence of such conditions. PJM employs a market-based congestion management system using the LMP approach to quantify and charge congestion. Generally the LMP at the load location is higher than the LMP at the generator location during congestion. The difference between load LMP and the generator LMPs is the congestion cost. PJM offers FTRs (or auction revenue rights (ARRs) which, for analytical purposes are equivalent to FTRs) that provide market participants a financial means to hedge against potential congestion costs.

FTRs are financial contracts that entitle the holder to a stream of revenues based on the hourly LMP price differences between loads and generators, at times of congestion. The FTRs act as a hedge by providing a certain stream of revenue from which AEP would offset congestion costs as part of its market participation. The CERA study results for the study period revealed that there would not be any significant congestion on the AEP-east system, and that the FTR revenues are expected to be greater than the congestion costs incurred, resulting in net FTR revenues. (See Exhibit JCB-1 and Exhibit JCB-2).

Q. Please explain how the FTR Revenue and congestion costs were determined.

A. Before FTR revenues are calculated, it is necessary to determine how many FTRs are going to be allocated to the AEP load zone by PJM, and to which generators they will be assigned. Based on PJM's existing allocation rules, AEP estimates a total allocation of FTRs equal to AEP's forecasted peak demand for each of the study years. The FTRs were then assigned to AEP's generation in a two-step process. First, FTRs were allocated to each of AEP's generating units based on the unit's expected generation as a share of AEP's total generation. Second, the unit's allocation was compared to its rated capability. If the allocation exceeded the unit's rating, then the excess was reallocated to the remaining units in such a way that the unit's allocation was capped at the unit's rated capacity.

Following the FTR allocation to each generating unit that is expected to be in service, the FTR revenues were computed for those units by multiplying the FTRs assigned to that unit by the difference between the sink LMP (AEP load-weighted LMP) and the unit LMP. This calculation was done for each hour of the year for all the FTRs allocated to arrive at the total FTR revenues.

Correspondingly, the congestion cost was calculated as the actual generation of the generator multiplied by the difference between the sink LMP (AEP load-weighted LMP), and the unit LMP. This was done for each hour of the year for all the AEP owned generators. Then, since congestion cost only applies to the internal load, this value was scaled down to only reflect a generation volume equal to our internal load in that hour. These values were then summed for the year to get the congestion cost for AEP load. The difference between the total FTR revenues and congestion cost is the Net FTR Revenue.

Q. Please explain the benefits associated with avoided contract costs.

A. As part of AEP's merger conditions, FERC required AEP to contract with independent parties to perform certain functions, including calculation of available transmission capability (ATC) and market monitoring, on an interim basis pending AEP's participation in an RTO. AEP contracted with Southwest Power Pool ("SPP") and Charles River Associates ("CRA"), respectively, to perform these functions. In addition, PJM is currently functioning, on a contractual basis, as AEP's Reliability Coordinator. These contracts will expire upon AEP's entry into PJM, and the functions performed by the contractors will be provided by PJM (with the costs of providing these functions reflected in its administrative fees). A benefit of joining PJM, therefore, is the avoidance of these costs.

Q. Please explain the PJM administrative charges.

A. The administrative charges represent the allocation of the costs incurred to operate PJM, including: wages and salaries, capitalized projects, depreciation, interest, licenses, leases and other expenses. The costs are recovered from users of the various PJM services in accordance with Schedule 9 of the PJM Tariff. The billable service categories include:

Schedule 9-1 Control Area Administration

Schedule 9-2 Financial Transmission Rights Administration

Schedule 9-3 Market Support (Generation and Load)

Schedule 9-4 Regulation and Frequency Response Administration

Schedule 9-5 Capacity Resource and Obligation Management

Q. How were the Schedule 9 administrative costs estimated for this cost/benefit study?

A. The administration fees are based on PJM's estimated 2005 administrative service rates (which are regarded as representative of 2004, as well), reflecting the incremental costs of the market integration of AEP, ComEd, DP&L and DVP ("New PJM Companies"), as well as the additional billing determinants that will result from integration of the new transmission zones. These administrative charges are estimated by PJM to be lower than the current per-unit charge as a result of the four New PJM Companies being integrated into the PJM market structure. Adjustments were made to the estimated individual 2005 administrative service rates to reflect PJM's bundled rate estimates through 2008. Projected load and generation outputs from the CERA study are used to calculate the estimated annual administrative fees AEP will be expected to pay.

PJM's tariff also provides for recovery of FERC's annual assessment (used to fund FERC operations). In the future, FERC fees may be calculated on a different basis if AEP is a member of PJM than they would be on a stand-alone basis. However, it is unknown whether any different method of calculating these fees would result in a net cost or net benefit.

Q. Please discuss the deferral of the RTO development and implementation costs, i.e., costs incurred by AEP in connection with the Midwest ISO, Alliance RTO and PJM.

A. On July 2, 2003, the FERC issued an Order reinforcing prior Orders and finding it reasonable for AEP to defer RTO start-up costs, including PJM integration costs and related carrying charges until AEP integrates with PJM. The FERC order on accounting for RTO implementation costs provides that AEP will have to make a separate filing to request recovery of these deferred costs, demonstrating that the costs were prudently incurred, to seek approval to establish a regulatory asset and to seek approval of an amortization plan for the regulatory asset.

Q. Will AEP incur PJM integration costs even if it does not participate in PJM?

A. Yes. AEP's share of the costs of the project is expected to be about $36 million ($13 million in expenses and $23 million in capital costs). AEP, ComEd, DVP and DP&L are jointly funding the expense portion of PJM's project to integrate their systems into the PJM RTO and markets. PJM is funding the capital-related integration cost. If AEP fully participates in PJM, the integration project costs, both expense and capital, will be recoverable from PJM transmission service customers throughout the expanded PJM region. If AEP does not participate in PJM, the integration costs charged to AEP by PJM would likely still be recoverable, but only from customers in the AEP east zone.

Q. Would there be additional costs associated with supplying capacity as a member of PJM?

A. There should be no difference. There are two factors to consider that may have an impact on the cost of capacity reserves: the amount of reserve required in each case and the price of capacity in each case.

Q. What amount of reserve would be required in each case?

A. On the surface, there appears to be a different AEP reserve level required as a member or non-member of PJM. As a non-member of PJM, considering our System and load characteristics, the AEP system currently uses a reserve margin of approximately 12%, which is sufficient to meet the four percent operating reserve criterion established by ECAR. On the other hand, as a member of PJM, based on current PJM requirements, AEP would need a 15% Installed Reserve Margin. However, in the PJM system, AEP would be credited with the diversity between our own peak load and our load at the time of the PJM peak. In addition, the PJM calculations take into account the differences between recent AEP unit forced outage rates and longer-term forced outage statistics for PJM as a whole. These adjustments, given current load and forced outage statistics, result in an AEP reserve requirement of just over 12% as a PJM member, which for all practical purposes is the same reserve that AEP would carry as a non-member.

In more practical terms, membership in PJM may allow some small savings in capacity requirements, by allowing capacity to be matched to load in small increments. Without use of the PJM market, it is likely that in the long term AEP would construct and own or purchase capacity in blocks that would not match precisely with requirements and so there would be years when capacity exceeded minimum requirements.

Q. What would the price of capacity be in each case?

A. PJM has a short-term market for capacity. PJM capacity prices currently are below the cost of new construction -- on the order of $15 to $25/MW-day. AEP expects the price to rise over the coming years as the current, temporary capacity surplus in the area is depleted by load growth (perhaps combined with retirements).

Under the ECAR paradigm in which AEP currently operates, there is no centralized capacity market. Currently, there is a surplus of capacity in the ECAR region for the foreseeable future, as there is in the PJM region. Therefore, the current prices of capacity in ECAR and PJM are expected to be nearly the same considering the surplus capacity available in both regions. In the long term, the cost of capacity to a non-member of PJM should approach the cost of owning a combustion turbine, which currently is the lowest capacity cost alternative, just as it should for a PJM member. Given AEP's position adjacent to the existing PJM system, as markets tighten it can be expected that the price of incremental capacity for AEP either as a PJM member or a non-member will be about equal.

Q. What then do these factors mean for AEP's cost of capacity?

A. Given current data, with equal reserve requirements as a member or a non-member and with long-term capacity prices about the same in either case, we can calculate no difference in capacity cost for AEP as a member of PJM relative to the cost as a non-member.

C. <u>Allocation Among Operating Companies</u>

Q. Please describe how the costs and benefits were allocated among the AEP-east operating companies.

A. The results of CERA's study were presented for the AEP east zone as a whole. Under my direction and supervision, AEP analysts processed those results for each of the five operating companies that are members of the AEP east zone Interconnection Agreement ("AEP pool"). First, the projected off-system sales were identified (i.e., the generation and purchase volume over and above the forecasted internal energy requirements) and matched with the most expensive generation resources. Second, the remaining resources, even though they were adequate to meet the combined energy requirements of the whole of the AEP System, had to be sorted by operating company in order to identify the surplus and deficit companies and provide for the appropriate receipts and deliveries and the corresponding charges and credits for each company. The process was similar to what AEP does for each operating hour of the System to identify off-system sales and resources assigned to these sales and primary energy receipts and deliveries, except, for the purposes of this study, this process was done on an annual basis in the aggregate.

Finally, the net revenues from off-system sales and the net FTR revenues on an annual basis were allocated to the five members of the AEP pool. The allocation was effected based on the average annual member-load-ratio of each member, based upon the forecast that was used in the CERA study. The administrative costs and avoided contract costs were allocated on a member-load-ratio basis.

D. Summary of Costs and Benefits

Q. Please summarize your findings.

A. My findings are summarized on Exhibit JCB-1. For Kentucky Power, there is a direct net benefit for each of the study years ranging from approximately \$2.3 million to \$3.2 million, for a total of approximately \$13.4 million nominal benefit for the five-year study period, comparing Case I (Full PJM membership) with Case 2 (AEP Stand-Alone).

Q. Please summarize your findings for Case IA.

A. My findings for Case IA are quantified in Exhibits JCB-4 and JCB-5 for Kentucky Power and the AEP east zone, respectively. Even without participating in the PJM market, AEP would accrue benefits associated with off-system sales and avoided contract costs, but would not accrue net FTR revenues. The annual administrative cost to fulfill the non-market functions assumed in Case IA are estimated to be about \$12 million dollars, based on the Alliance RTO's estimated costs and other RTO cost estimates. The annual administrative cost of participating in PJM under this limited AEP participation scenario would thus be reduced, by about \$39 million for 2004, thereby increasing the net benefit under Case IA as compared to Case I. Kentucky Power's share of the net benefit over the five year study period would be \$20.3 million.

E. **Relationship to PJM Study**

Q. Please describe how the current CERA market analysis results associated with the production cost/savings compare with the corresponding PJM market analysis results that were filed by PJM as part of Mr. Andrew L. Ott's testimony in the initial stage of this proceeding.

A. PJM conducted an independent market analysis for the year 2004 using the GE-MAPS program to assess the economic cost/benefit of AEP being part of the PJM energy market and compared the corresponding results with AEP not being a part of PJM. This comparison revealed that the potential annual savings in the AEP territory considering generation production cost, purchased power costs, and off-system sales would be in the range of $61 million to $80 million if AEP joins PJM and participates in its energy market. These savings did not include PJM administrative costs.

The CERA study also assessed the potential benefits associated with the production cost savings and off-system sales benefits for 2004. The corresponding CERA results revealed a net savings of $62 million, with AEP's participation in PJM, excluding PJM administrative costs. The CERA and PJM study results thus project a similar amount of potential savings with AEP as part of the PJM energy market, for the year 2004.

FLOW THROUGH OF BENEFITS TO RETAIL CUSTOMERS

Q. How would the benefits be flowed through to Kentucky retail customers?

A. Some of the benefits associated with a share of increased off-system sales profits will be automatically passed through to Kentucky customers through existing rate mechanisms.

Other benefits, and costs, would not be passed through to customers unless and until a base rate case.

Q. Please describe how the increased off-system sales profits will be flowed through to Kentucky retail customers.

A. Pursuant to previous KPSC Orders, the Company has implemented a "System Sales Clause Tracker" whereby increases in the overall level of System Sales profits are used to reduce Kentucky jurisdictional customers' cost of service.

Q. Please explain the mechanics of the System Sales Clause Tracker.

A. When Kentucky Power base rates were last established in Case No. 91-066 with a test year ending December 31, 1990, off-system sales profit levels were $11,315,336 on an annual basis. This amount is reflected in the base rates of Kentucky Power Company as a reduction to cost of service. If off-system sales profits increase (or decrease) from this base level a credit (or a debit) is computed on a monthly basis. The credit is computed as the difference between the current month net revenue level (profit) and the base month net revenue level (per the Company's System Sales Clause Tariff) multiplied by 0.5 and that result is divided by the current month sales level of KWhs. The resulting factor is credited (or charged) to the customer's current monthly bill on a per kilowatt-hour basis.

Q. Why is the increase (or decrease) in off-system sales profit multiplied by 0.5?

A. Pursuant to the KPSC Order in Case No. 9061, the Company is allowed to retain (or charge) one-half of the difference from the base level of off-system sales that are built into base rates as an incentive to make these sales, thereby further reducing Kentucky jurisdictional customers' cost of service.

Q. When would the ratepayers begin seeing the effects of the increased level of off-system sales profits which are a result of AEP's membership in PJM?

A. The effects of the increased level of off-system sales profit which are a result of AEP's membership in PJM would be reflected on the customers' bills the second month after membership in PJM.

Q. When will the remaining benefits and costs associated with the PJM membership be reflected in the level of rates the Kentucky retail customers pay?

A. The remaining benefits (net FTR revenues and avoided contract costs) and the cost associated with AEP's membership in PJM will not be reflected in retail rates until the next change in base rates.

OTHER BENEFITS

Q. You have described the net benefits to Kentucky Power and its customers of the Company's participation in PJM. Are there other benefits not captured in the net benefit totals?

A. Yes. There are many benefits that are not captured in the totals, but are real nonetheless. For example, as explained below, membership in PJM should enhance reliability. While it is difficult to quantify the value of enhanced reliability, the magnitude of that value can readily be appreciated, particularly after the August 14, 2003 electricity blackout, which had a huge economic impact on electricity customers and the public in general over a large section of the United States and Canada. Although AEP was able to avoid most of the effects of the blackout, it does not follow that AEP should not continue to take steps to enhance reliability. It should be noted that PJM has been functioning as AEP's Reliability Coordinator in anticipation of AEP's joining PJM.

Another benefit associated with AEP's membership in an RTO is the merger savings already passed through to Kentucky customers by way of the Net Merger Savings Credit tariff. The Kentucky Commission approved AEP's merger with Central and South West Corporation in Case No. 99-149 on June 14, 1999. In the FERC's June 15, 2000 merger order, FERC approved the merger contingent on AEP joining an RTO. The Kentucky ratepayers started receiving the Net Merger Saving Credit on July 28, 2000. To date the Kentucky ratepayers have received approximately $8.7 million in credits to their monthly bills. Clearly, if AEP had not agreed to join an RTO, the FERC would not have approved the merger and therefore, the Kentucky ratepayers would not have received the credits. The net merger savings to be distributed in the next five and one half years range from approximately $4 million to $5.2 million per year. To say this another way, if it were not for the FERC's order approving the merger contingent on AEP joining an RTO, the Kentucky ratepayers would not have received the past, current, or the future net merger savings amounts. The Net Merger Savings Credits are shown on Exhibit JCB-6.

ADDITIONAL REHEARING ISSUES

Q. The Commission's August 25, 2003 rehearing order stated that the Company could provide testimony on other issues set forth in its request for rehearing. Do you wish to provide such additional testimony?

A. Yes. In its request for rehearing, the Company pointed out several areas where findings made by the Commission in its July 17, 2003 order denying Kentucky Power's application were not supported by any evidence, or were contrary to the evidence then in the record. I continue to believe that the existing record supports the Company's application, but, in case there is any doubt, I am adding additional information addressing certain of the concerns expressed by the Commission in its order.

Q. Will there be changes in flows and redispatch that will result in significant unhedged congestion costs to the Company under PJM?

A. In the initial round of hearings in this case, AEP and PJM testified that no significant unhedged congestion costs are expected. This testimony was undisputed. The CERA study results for the congestion costs and FTR values are derived from the LMP results of a centralized security-constrained economic dispatch in the MISO/PJM region, which captures the impact of changes in flows and redispatch. These results confirm that congestion costs borne by the Kentucky customers will not be significant because of the absence of major congestion in the AEP system and the availability of FTRs to manage the congestion risk. The CERA results reveal that congestion costs are not expected to exceed revenues that AEP will receive as an FTR holder. In fact, the FTR values projected by the study are greater than the projected congestion costs.

Q. Are there benefits resulting from enhanced reliability from joining PJM?

A. Reliability under PJM would be enhanced on a regional level because PJM will have functional control of transmission and generation resources over a wider area. Also, PJM's security-constrained generation dispatch uses LMP as the primary means for managing congestion. Such generation redispatch provides quicker relief to congested transmission facilities then does curtailing transactions using the transmission loading relief process. The reliability of the AEP system in southwest Virginia should improve prior to the planned addition of the Wyoming – Jackson's Ferry 765 kV line, as PJM will be able to internalize the operations and redispatch of Allegheny Power, DVP and AEP in

Virginia and West Virginia, thereby better managing the critical Kanawha – Matt Funk 345 kV constraint. This will enhance the reliability of the region and reduce the exposure to potential congestion on this critical southwest Virginia/WV interface, which in turn will enhance the reliability of the AEP's transmission in Kentucky and minimize curtailments.

Q. Would the Commission's approval of the Company's participation in PJM force it to acquiesce in a law – KRS 278.214 -- that it is required to enforce?

A. No, it would not. It is true that there is a conflict between KRS 278.214, which requires that Kentucky native load customers be given curtailment priority in a transmission emergency and FERC's pro-forma open access transmission tariff, which requires curtailment of native load, network service and long-term point-to-point transmission service to be curtailed pro-rata, and which requires actions to be taken irrespective of state or company boundaries. But any such conflict is a function of FERC's tariff. It is not associated with PJM membership. AEP will be subject to the FERC's requirement whether or not it joins PJM, since the pro-rata curtailment provision is in both AEP's and PJM's tariffs. The Company understands that the Commission believes that KRS 278.214 is a valid, constitutional requirement, and there are currently court proceedings pending on that issue, which will be determined one way or another regardless of whether or not the Company joins PJM.

Q. On the basis of the record in this proceeding, including your current testimony and the cost/benefit analysis, what is your recommendation?

A. I recommend that the Commission approve Kentucky Power's application in this case.

Q. Does this conclude your testimony?

A. Yes.

Kentucky Power Company
Estimated Net Benefits of Joining PJM
(In Millions)
2004-2008

Benefits	2004 Case I	2004 Case II	2004 Net Benefits (Costs)	2005 Case I	2005 Case II	2005 Net Benefits (Costs)	2006 Case I	2006 Case II	2006 Net Benefits (Costs)	2007 Case I	2007 Case II	2007 Net Benefits (Costs)	2008 Case I	2008 Case II	2008 Net Benefits (Costs)	5-Year Total Nominal Net Benefits (Costs)
Off System Sales Profit*	11.2	6.6	**4.6**	12.7	7.9	**4.8**	13.5	8.4	**5.1**	14.4	9.4	**5.0**	15.1	10.3	**4.8**	**24.3**
Net FTR Revenues	1.4	0.0	**1.4**	1.7	0.0	**1.7**	1.9	0.0	**1.9**	1.7	0.0	**1.7**	1.6	0.0	**1.6**	**8.3**
Avoided Contract Costs	0.0	(0.1)	**0.1**	0.0	(0.1)	**0.1**	0.0	(0.1)	**0.1**	0.0	(0.1)	**0.1**	0.0	(0.1)	**0.1**	**0.5**
Costs																
PJM Admin. Charge	(3.8)	0.0	**(3.8)**	(3.9)	0.0	**(3.9)**	(3.9)	0.0	**(3.9)**	(4.1)	0.0	**(4.1)**	(4.0)	0.0	**(4.0)**	**(19.7)**
Total	8.8	6.5	**2.3**	10.5	7.8	**2.7**	11.5	8.3	**3.2**	12.0	9.3	**2.7**	12.7	10.2	**2.5**	**13.4**

*Calculated on a marginal cost basis.

Case No. 2002-00475
Exhibit JCB - 1

AEP System - Eastern Portion
Estimated Net Benefits of Joining PJM
(In Millions)
2004-2008

			2004 Net Benefits			2005 Net Benefits			2006 Net Benefits			2007 Net Benefits			2008 Net Benefits	5-Year Total Nominal Net Benefits
Benefits	Case I	Case II	(Costs)	Case I	Case II	(Costs)	Case I	Case II	(Costs)	Case I	Case II	(Costs)	Case I	Case II	(Costs)	(Costs)
Off System Sales Profit*	151	89	**62**	171	107	**64**	187	116	**71**	199	130	**69**	210	143	**67**	**333**
Net FTR Revenues	19	0	**19**	23	0	**23**	26	0	**26**	24	0	**24**	22	0	**22**	**114**
Avoided Contract Costs	0	(2)	**2**	0	(2)	**2**	0	(2)	**2**	0	(2)	**2**	0	(2)	**2**	**10**
Costs																
PJM Admin. Charge	(51)	0	**(51)**	(52)	0	**(52)**	(54)	0	**(54)**	(56)	0	**(56)**	(56)	0	**(56)**	**(269)**
Total	119	87	**32**	142	105	**37**	159	114	**45**	167	128	**39**	176	141	**35**	**188**

*Calculated on a marginal cost basis.

Case No. 2002-00475
Exhibit JCB - 2

Calculation of Forecasted
PJM Administration Charges
2004-2008

ANNUAL ADMINISTRATION OBLIGATION

CASE I - AEP IN PJM

PJM Schedule		2004 AEP-East	2004 KPCo*	2005 AEP-East	2005 KPCo*	2006 AEP-East	2006 KPCo*	2007 AEP-East	2007 KPCo*	2008 AEP-East	2008 KPCo*
Control Area Services	Schedule 9-1	$25,694,953	$1,910,420	$26,280,826	$1,946,095	$27,373,883	$1,981,595	$28,534,918	$2,063,931	$28,342,842	$2,041,818
FTR Administration (internal load)	Schedule 9-2	3,236,790	240,655	3,310,592	245,149	3,452,232	249,907	3,591,721	259,789	3,574,432	257,502
Market Support (Generation)	Schedule 9-3(G)	10,954,066	814,435	11,045,311	817,905	11,363,224	822,584	11,700,013	846,262	11,504,184	828,761
Market Support (Load)	Schedule 9-3(L)	8,267,888	614,717	8,456,405	626,197	8,795,263	636,689	9,171,938	663,406	9,106,591	656,039
Regulation & Frequency Response	Schedule 9-4	1,164,963	86,615	1,191,525	88,232	1,240,754	89,818	1,293,318	93,546	1,284,673	92,548
Capacity Resource & Obligation Mgmt.	Schedule 9-5	1,784,484	132,676	1,832,907	135,727	1,906,922	138,042	1,987,956	143,789	1,970,148	141,929
Total		$51,103,142	$3,799,519	$52,117,567	$3,859,306	$54,132,277	$3,918,636	$56,279,862	$4,070,722	$55,782,869	$4,018,598

*KPC allocation based on average Member Load Ratio (MLR) share of the AEP East system.

Kentucky Power Company
Estimated Net Benefits of Limited AEP Participation in PJM
(In Millions)
2004-2008

	Case IA	Case II	2004 Net Benefits (Costs)	Case IA	Case II	2005 Net Benefits (Costs)	Case IA	Case II	2006 Net Benefits (Costs)	Case IA	Case II	2007 Net Benefits (Costs)	Case IA	Case II	2008 Net Benefits (Costs)	5-Year Total Nominal Net Benefits (Costs)
Benefits																
Off System Sales Profit*	11.2	6.6	**4.6**	12.7	7.9	**4.8**	13.5	8.4	**5.1**	14.4	9.4	**5.0**	15.1	10.3	**4.8**	**24.3**
Avoided Contract Costs	0.0	(0.1)	**0.1**	0.0	(0.1)	**0.1**	0.0	(0.1)	**0.1**	0.0	(0.1)	**0.1**	0.0	(0.1)	**0.1**	**0.5**
Costs																
PJM Admin. Charge	(0.9)	0.0	**(0.9)**	(0.9)	0.0	**(0.9)**	(0.9)	0.0	**(0.9)**	(0.9)	0.0	**(0.9)**	(0.9)	0.0	**(0.9)**	**(4.5)**
Total	10.3	6.5	**3.8**	11.8	7.8	**4.0**	12.6	8.3	**4.3**	13.5	9.3	**4.2**	14.2	10.2	**4.0**	**20.3**

*Calculated on a marginal cost basis.

Case No. 2002-00475
Exhibit JCB – 4

AEP System - Eastern Portion
Estimated Net Benefits of Limited AEP Participation in PJM
(In Millions)
2004-2008

Benefits	Case IA	Case II	2004 Net Benefits (Costs)	Case IA	Case II	2005 Net Benefits (Costs)	Case IA	Case II	2006 Net Benefits (Costs)	Case IA	Case II	2007 Net Benefits (Costs)	Case IA	Case II	2008 Net Benefits (Costs)	5-Year Total Nominal Net Benefits (Costs)
Off System Sales Profit*	151	89	**62**	171	107	**64**	187	116	**71**	199	130	**69**	210	143	**67**	**333**
Avoided Contract Costs	0	(2)	**2**	0	(2)	**2**	0	(2)	**2**	0	(2)	**2**	0	(2)	**2**	**10**
Costs																
PJM Admin. Charge	(12)	0	**(12)**	(12)	0	**(12)**	(12)	0	**(12)**	(12)	0	**(12)**	(12)	0	**(12)**	**(60)**
Total	139	87	**52**	159	105	**54**	175	114	**61**	187	128	**59**	198	141	**57**	**283**

*Calculated on a marginal cost basis.

Case No. 2002-00475
Exhibit JCB - 5

Kentucky Power Company
Net Merger Savings Credit

Exhibit JCB-6

Ln No.	Description	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9		Total
1	Net Savings to be Distributed per Tariff	$1,463,815	$2,553,660	$3,184,645	$3,695,003	$4,037,167	$4,299,432	$4,504,920	$4,626,369	$5,242,785		$33,607,796
2	Net Savings to be Distributed January through July	$853,892	$1,489,635	$1,857,710	$2,155,418	$2,355,014	$2,508,002	$2,627,870	$2,698,715	$3,058,291		
3	Net Savings to be Distributed August through December	$609,923	$1,064,025	$1,326,935	$1,539,585	$1,682,153	$1,791,430	$1,877,050	$1,927,654	$2,184,494		
	Total (Ln 2 + Ln 3)	$1,463,815	$2,553,660	$3,184,645	$3,695,003	$4,037,167	$4,299,432	$4,504,920	$4,626,369	$5,242,785		
		Amt Distrib twelve months 31-Dec-00	Amt Distrib twelve months 31-Dec-01	Amt Distrib twelve months 31-Dec-02	Amt Distrib twelve months 31-Dec-03	Amt Distrib twelve months 31-Dec-04	Amt Distrib twelve months 31-Dec-05	Amt Distrib twelve months 31-Dec-06	Amt Distrib twelve months 31-Dec-07	Amt Distrib twelve months 31-Dec-08	Amt Distrib seven months 31-Jul-09	
4	Net Merger Savings Credit Tariff (Ln. 3 + prior year Ln. 2)	$609,923	$1,917,917	$2,816,570	$3,397,294	$3,837,571	$4,146,444	$4,385,052	$4,555,524	$4,883,209	$3,058,291	
5	Net Merger Savings Credit Tariff Distributed August 2000 through December 2003											$8,741,705
6	Net Merger Savings Credit Tariff to be Distributed January 2004 through December 2008											$21,807,800
7	Net Merger Savings Credit Tariff to be Distributed January 2009 through July 2009											$3,058,291
8	Total (Ln.5+Ln6+Ln7)											$33,607,796

Note: Net Merger Savings Tariff first became effective July 28, 2000 with cycle 1 of August revenues.

Case No. 2002-00475
Exhibit - 6

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

STATE OF OHIO

CASE NO. 2002-000475

COUNTY OF FRANKLIN

AFFIDAVIT

J. Craig Baker on first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

J. Craig Baker

J. Craig Baker

Subscribed and sworn to before me by J. Craig Baker this 18 day of Dec, 2003.

Catherine Hurston

Notary Public

My Commission Expires ____________

NOTARIAL SEAL STATE OF OHIO

CATHERINE HURSTON
Notary Public, State of Ohio
My Commission Expires 11-14-04

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

RECEIVED

DEC 23 2003

PUBLIC SERVICE
COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY POWER COMPANY	)
d/b/a AMERICAN ELECTRIC POWER, FOR	)
APPROVAL, TO THE EXTENT NECESSARY,	)
TO TRANSFER FUNCTIONAL CONTROL OF	)CASE NO. 2002-00475
TRANSMISSION FACILITIES LOCATED IN	)
KENTUCKY TO PJM INTERCONNECTION, L.L.C.	)
PURSUANT TO KRS 278.218	)

DIRECT TESTIMONY AND EXHIBITS ON REHEARING

OF

HOFF STAUFFER

December 23, 2003

DIRECT TESTIMONY ON REHEARING OF
HOFF STAUFFER
FOR KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
CASE NO. 2002-00475

Q. Please state your name, address, and position.

A. My name is Hoff Stauffer. I am a Senior Consultant at Cambridge Energy Research Associates (CERA). My office address is 55 Cambridge Parkway, Cambridge, MA 02142. I am also a Research Director for the CERA Transmission Advisory Service.

Q. Please summarize your educational and employment background.

A. With over 30 years of experience in energy and environmental issues, I have expertise in utility and merchant power producer market strategies, generation and transmission issues, and valuation in the new energy markets. I have advised energy consumers on integrating their energy strategies with procurement, risk management, consumption, distributed generation, and load management tactics. For private clients, in 1999, I forecasted the current surplus of generation capacity and recent dramatic price decreases throughout the US electricity market, and earlier I forecasted the price spikes in California. I have used General Electric Multi-Area Production Simulator (GE MAPS) for over seven years to analyze the North American electricity markets, including transmission constraints and locational spot prices. I have also used this work to value generation assets and transmission investments.

I have contributed to the design of the acid rain mitigation program, considered the impact of global warming issues for the energy industry, and led the development of the Coal and Electric Utilities model.

I was the first Director of Economic Analysis for the US Environmental Protection Agency. After my government service, I held executive positions with major firms throughout my career, including McKinsey & Co., ICF, Booz Allen & Hamilton, Putnam, Hayes, & Bartlett, and A.T. Kearney. I have testified before the US Congress and in 1986 wrote *Vision 2000* for the US electricity industry.

I hold a BA degree with high honors from Wesleyan University (Connecticut) and an MBA degree from Stanford University, where I won the Arbuckle Award.

Q. What is the purpose of your testimony?

A. I am sponsoring Exhibit HS-1, a report, entitled, "Economic assessment of AEP's participation in PJM." I am submitting this report on behalf of AEP in this proceeding.

Q. Was the report prepared by you or under your direction and supervision?

A. Yes, it was.

Q. Is the information in the report true and accurate to the best of your knowledge and belief?

A. Yes, it is.

Q. Does this conclude your testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

COMMONWEALTH OF MASSACHUSETTS

CASE NO. 2002-000475

COUNTY OF Middlesex

AFFIDAVIT

Hoff Stauffer, on first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Hoff Stauffer

Hoff Stauffer

Subscribed and sworn to before me by **Hoff Stauffer** this 17th day of December 2003.

Elizabeth L. Molloy

Notary Public

My Commission Expires February 14, 2008

EXHIBIT HS-1

ECONOMIC ASSESSMENT OF AEP'S PARTICIPATION IN PJM

Prepared for

American Electric Power
by

Cambridge Energy Research Associates

December 18, 2003

PRIVATE AND CONFIDENTIAL

Table of Contents

Table of Contents *(continued)*

Economic Assessment of AEP's Participation in PJM

1. Introduction

This study provides an economic assessment of the costs and benefits of American Electric Power's (AEP) participation in the PJM regional transmission organization (RTO). Cambridge Energy Research Associates (CERA) undertook this study at the request of AEP in connection with ongoing RTO proceedings in Kentucky and Virginia.

For the purpose of fulfilling the requirements for a cost/benefit analysis of RTO participation, CERA conducted a five-year economic cost/benefit analysis, to quantify the costs and benefits of AEP's integration into the PJM markets. This study was conducted for the period 2004–08. The General Electric (GE) Multi-Modeling Production Simulation ("GE-MAPS") production cost-simulation model was used. This model has a detailed representation of the Eastern Interconnect transmission network. Two scenarios were simulated to assess the economic impact of AEP joining PJM: a scenario that includes through and out rates for AEP, the existing situation, and a scenario that includes no through and out rates for AEP or any of the PJM/MISO footprint. To a large extent, the costs and benefits of joining an RTO are driven by the elimination of wheeling rates between regions, including AEP's through and out rates

In addition, CERA assessed other benefits of joining PJM, such as reliability enhancements, market efficiency, resource adequacy, and benefits of regional planning.

AEP post-processed the CERA results to quantify the benefits and costs on a jurisdictional basis.

2. Summary

To a significant extent, the net benefits are driven by the elimination of through and out rates between regions, including AEP, because lower cost generation in AEP and the Midwest would displace the higher cost generation in PJM.

In addition to the other qualitative benefits discussed below, AEP customers would primarily benefit because revenues from off-system sales for AEP would increase.

Market participants in PJM would benefit because market prices would be lower as a result of increased imports of lower cost power from AEP and the rest of the Midwest.

3. Approach

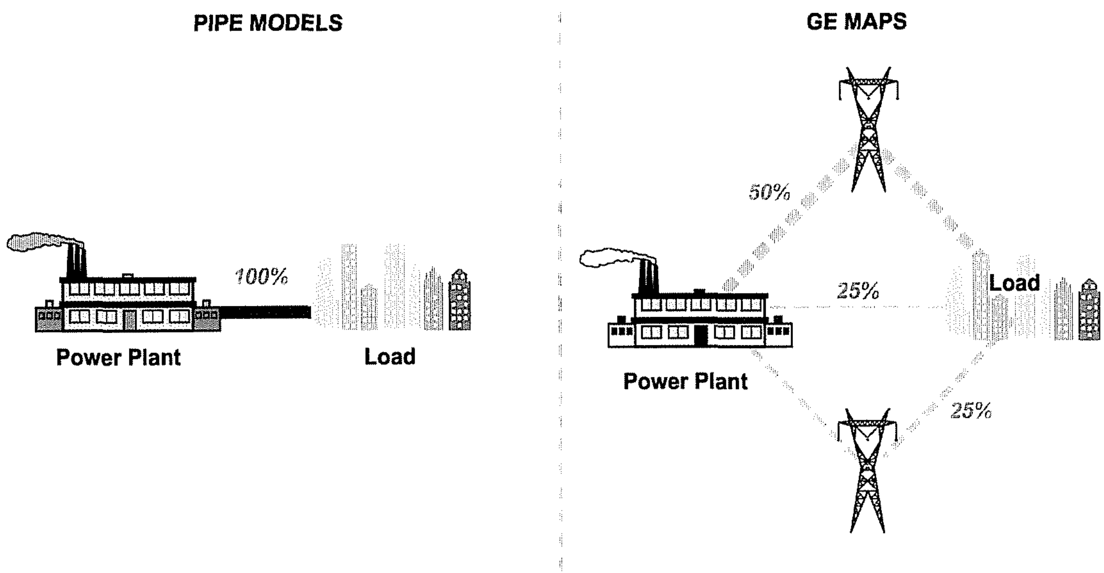
CERA used its proprietary version of the GE-MAPS electricity market simulation model. The CERA team has been working with this model since about 1996, because it was the only model that simulates electricity transmission properly. Other models assume that electricity flows as if through pipes from region to region. Instead, electricity flows according to Kirchoff's law, in inverse proportion to the impedance. Hence, more will flow on low-impedance, high-voltage lines than on higher impedance, low-voltage lines.

In Figure 1, we illustrate that 50 percent of the power will flow on the circuitous high voltage line, whereas only 25 percent will flow on the direct low-voltage line, and 25 percent will flow on the circuitous medium voltage line. It does not flow directly down a single line. These simultaneous flows down multiple lines are called "parallel flows."

CERA has three versions of GE-MAPS: one each for the eastern interconnect, western interconnect, and ERCOT.

Figure 1

GE MAPS Is Uniquely Well-structured for this Study



Source: Cambridge Energy Research Associates.
30127-3

CERA leases from GE the same version of GE-MAPS that GE will lease to anyone else. However, all of the databases for the CERA version of GE-MAPS are proprietary to CERA; CERA does not use any GE data inputs. Also, CERA has developed extensive ancillary models to facilitate data management and to provide helpful outputs for summarizing the results of a model run and for diagnosing apparent anomalies, where often the apparent anomaly leads to a new insight.

This study is intended to simulate a security-constrained unit commitment and economic dispatch of the PJM/MISO region and much of the Eastern Interconnect. The GE-MAPS model is very well structured for this purpose.

Material that documents the GE-MAPS model and some of the ancillary models used for the study are provided in the Appendix B.

At present, CERA is in process of conducting a multi-client study entitled *Grounded in Reality*. The purpose of this study is to assess transmission bottlenecks and to find cost-effective solutions for them. The study is in three parts. The first part focused on the Eastern Interconnect, the second on the Western Interconnect, and the third on ERCOT. A prospectus for this study is provided at the end of Appendix A.

The findings of *Grounded in Reality* are that the major transmission congestion is between geographic regions and not within the regions. Apparently, transmission owners have done a very good job of designing and maintaining the transmission grids within their service territories and reliability councils.

For this cost/benefit study, CERA used the same software and assumptions that are being used for *Grounded in Reality,* except for the AEP-provided data and inputs and AEP allowance price assumptions. All these input data and assumptions have been thoroughly reviewed by the CERA clients who are participating in the *Grounded in Reality* Study. Appendix A documents the inputs used for *Grounded in Reality* as well as the AEP load data.

Two scenarios were assessed:

1. Scenario A in which wheeling rates were assumed to be eliminated between PJM and the Midwest, including AEP, and
2. Scenario B in which the existing wheeling rates were not eliminated

In the Scenario A, there are no wheeling rates between PJM, Dominion, AEP, NY, New England, TVA, Southwest Power Pool (SPP), and the rest of the Midwest. However, it was assumed that the wheeling rates between Southeast transmission owners and the rest of the Eastern Interconnect would remain in place. Hence, we assumed that there would be wheeling rates between Dominion and the utilities to the south, between TVA and the utilities to the south and the Carolinas, and between Entergy and both Ameren and the SPP. This is the way CERA expects the wheeling rate situation to work out.

Scenario B is the same as the first except that there are wheeling rates between AEP and all of its direct connects.

The costs and benefits of eliminating wheeling rates can be measured as the difference between Scenarios A and B.

Maps illustrating the wheeling rate assumptions used for each scenario are provided in Appendix A (see Figures A.6 and A.7).

The wheeling rates are $4.25 per megawatt-hour (MWh) in dispatch (real time) and $7.25 per MWh in commitment (day-ahead). The wheeling rate in dispatch represents AEP's current transmission service rate. The wheeling rate in commitment is $3 higher than in dispatch, representing inefficiencies associated with bilateral markets in the areas where there is no energy market.

CERA conducted GE-MAPS runs for these two scenarios for three years: 2004, 2006 and 2008. The values for the intermediate years are interpolated (simple linear interpolation). The interpolations are provided in Appendix C.

The results of these two scenarios were used by AEP in the post-processing analyses as comparative cases for different RTO participation alternatives as discussed in the testimony of Mr. Baker. As part of post-processing, AEP estimated potential transmission congestion costs of AEP's participation in the PJM energy market and expected hedging using the financial transmission rights (FTRs) , using the results of this study and AEP's pool agreements to develop benefits and costs on a jurisdictional basis for its operating companies. AEP further augmented such costs estimates with the PJM administrative costs to evaluate the total benefit and costs of joining PJM on a jurisdictional basis.

4. Study Results and Analysis

Tables 1 and 2 compare the change in average hourly power/energy flows from AEP and the rest of the Midwest to PJM and Dominion Virginia Power (DVP). The comparison reveals that additional energy would flow from AEP and the rest of the Midwest into PJM and DVP, if the wheeling rates were eliminated.

Table 1

Change in Interpool Flows with the Removal of Wheeling Rates
(average megawatts per hour)

Source to Sink	2004	2006	2008
AEP to PJM	563	348	255
AEP to DVP	195	248	187
Rest of Midwest to PJM	277	224	199
Rest of Midwest to DVP	19	113	122
Total Midwest to East	1,055	933	763

Source: Cambridge Energy Research Associates

Table 2

Change in Annual Interpool Energy Flows with the Removal of Wheeling Rates
(gigawatt-hours per year)

Source to Sink	2004	2006	2008
AEP to PJM	4,932	3,048	2,234
AEP to DVP	1,708	2,172	1,638
Rest of Midwest to PJM	2,427	1,962	1,743
Rest of Midwest to DVP	166	990	1,069
Total Midwest to East	9,242	8,173	6,684

Source: Cambridge Energy Research Associates

Flows from AEP to PJM would increase as a result of the elimination of the out rate. Similarly, flows from AEP to DVP would increase as a result of the elimination of the out rate.

The increased flows from AEP to PJM and DVP would be provided by AEP generating units. The average capacity factor of the AEP coal-fired power plants would increase from 69.8 percent to 75.5 percent in 2004. These low-cost units were already committed in the scenario with wheeling rates

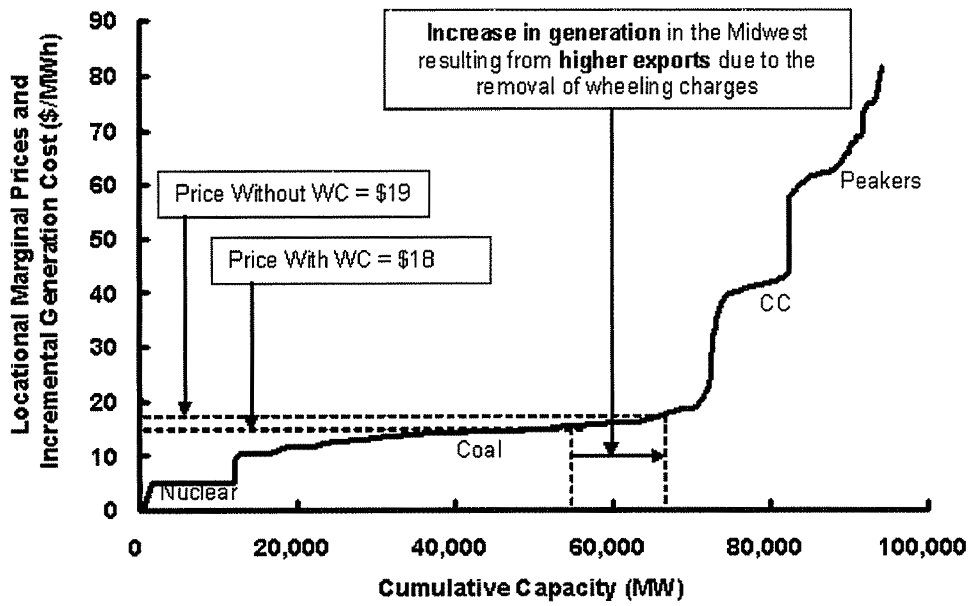
Flows from the rest of the Midwest to PJM and DVP would increase as a result of the elimination of the AEP through rates.

The increased flows are a result of eliminating the wheeling rates (both out of AEP and through AEP) so that it becomes economic to transmit more energy from the lower-cost generators in AEP and the rest of the Midwest to the higher-cost regions in the East.

This effect of eliminating wheeling rates is illustrated in the supply curves below. When the wheeling rates are eliminated, generation increases in the Midwest and decreases in the East, as lower-cost generation in the Midwest displaces higher-cost generation in the East. Marginal prices increase in the Midwest, as the relatively higher-cost generators in the Midwest are used to generate the increased exports to the East (see Figure 2).

Figure 2

Elimination of Wheeling Rates Results in Increased Generation in the Midwest
(regional supply curve: Midwest)



Source: Cambridge Energy Research Associates.
31204-16

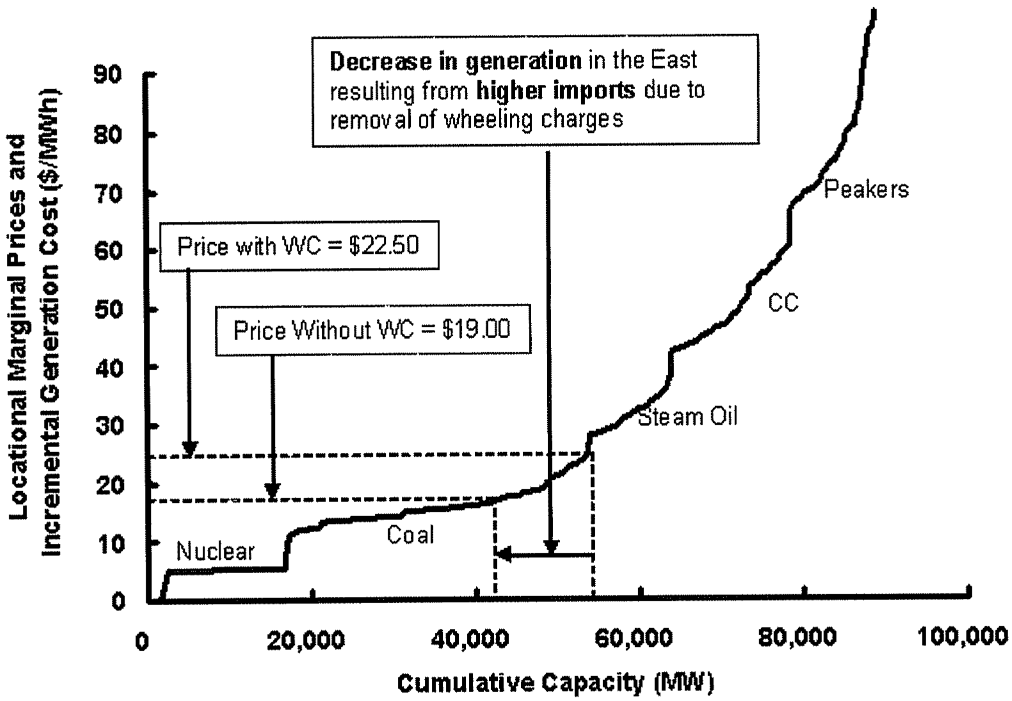
Prices decrease in the East, since lower-cost imports from the Midwest are used to displace higher-cost generation in the East (see Figure 3).

Without transmission constraints, prices in the East and the Midwest would be the same (i.e., $19 per MWh) if there were no wheeling rates, as shown in these illustrative curves in Figures 2 and 3. Of course, this would not really happen because there are material transmission constraints between the Midwest and the East.

The effect of transactional wheeling rates is to reduce the flow of electricity from the Midwest to the East by imposing a sort of "tax" on the transaction. As such, with wheeling rates, generation is higher in the East and lower in the Midwest. The effect of eliminating wheeling rates is to increase generation in the Midwest and reduce it in the East.

Figure 3

Elimination of Wheeling Rates Results in Reduced Generation in the East
(regional supply curve: East)



Source: Cambridge Energy Research Associates.
31204-17

Effect on LMPs

A major effect of these increased flows to the East would be lower locational marginal prices (LMPs) in the East and higher LMPs in the Midwest, although these price effects will not necessarily flow directly to customers as discussed below (see Tables 3, 4, and 5).

Table 3

Average Regional LMP
Scenario B with wheeling rates
(2002$ per MWh)

Region	2004	2006	2008
PJM	25.8	26.4	27.9
DVP	29.8	31.1	32.8
AEP	18.7	19.7	21.2
Rest of Midwest	19	19.9	21.4

Source: Cambridge Energy Research Associates

Table 4

Average Regional LMP
***Scenario A* Without Wheeling Rates**
(2002$ per MWh)

Region	2004	2006	2008
PJM	25.2	26	27.6
DVP	28.8	30.2	32
AEP	19.8	20.9	22.5
Rest of Midwest	19.3	20.5	22.1

Source: Cambridge Energy Research Associates

Table 5

Effect of Eliminating Wheeling Rates
Change in Average Regional LMP
(Scenario A minus Scenario B)
(2002$ per MWh)

Region	2004	2006	2008
PJM	(0.5)	(0.4)	(0.4)
DVP	(1.0)	(0.9)	(0.8)
AEP	1.1	1.2	1.3
Rest of Midwest	0.4	0.6	0.7

Source: Cambridge Energy Research Associates

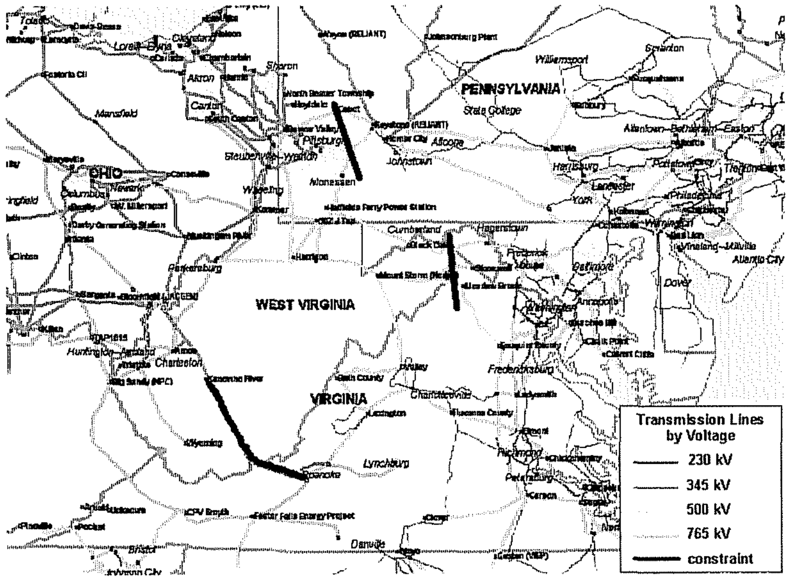
LMPs would be lower in the East because increased supplies of lower-cost energy would be available from the Midwest to displace some of the higher-cost generation in the East. LMPs would decrease by about $0.50 per MWh in PJM and by about $1 per MWh in DVP, because the increase in cheaper imports from the Midwest.

LMPs would increase by about $1 in AEP and $0.50 in the rest of the Midwest. This is because the increased flows to the East would be provided by increased generation from relatively higher-cost generators in the Midwest. The Midwest load and initial level of exports would be met by the lower-cost generators in the Midwest. Hence, the increased flows to the East would be provided by relatively higher-cost generators in the Midwest. But this increase in LMP would not materially impact AEP customers , as explained below.

There is still a price differential between the Midwest and the East even with no wheeling rates. This is because of the transmission constraints that exist between the Midwest and the East (see Figure 4).

Figure 4

Major Constraints Between the Midwest and the East
(shown as black barriers)



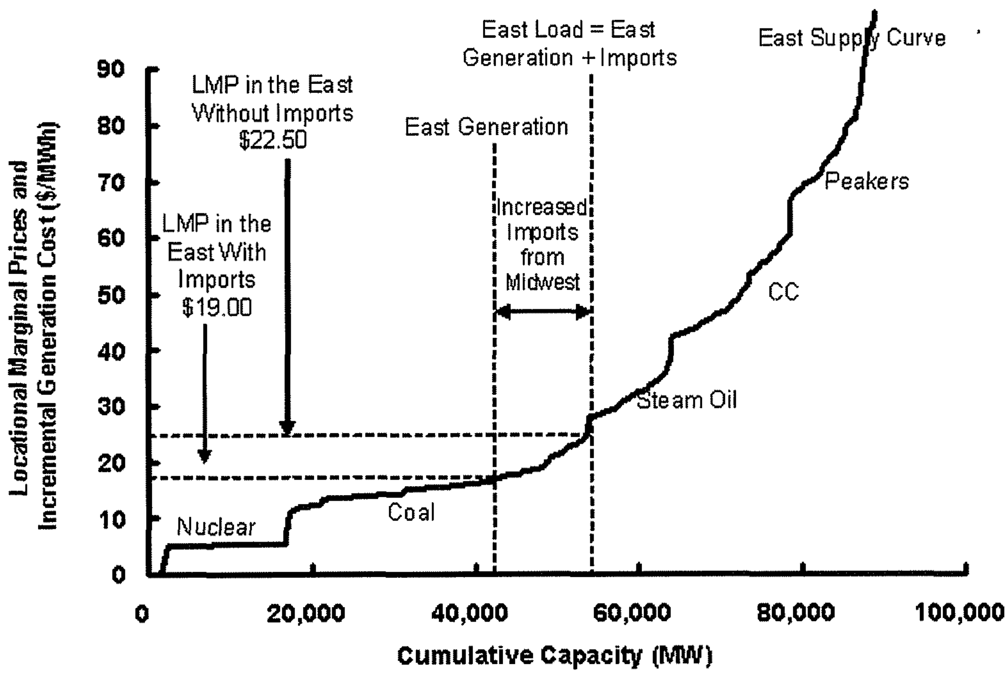
Sources: Cambridge Energy Research Associates and Platts POWERmap®.
31204-20

LMPs are set by the marginal generator in each hour. The higher the cost of the marginal generator, the higher the LMP, and vice versa.

With increased lower-cost imports from the Midwest, less power must be generated in the East. The higher-cost generators are no longer needed, and the marginal generators become lower-cost generators, which result in lower LMPs, as shown in Figure 5.

Figure 5

Elimination of Wheeling Rates Results in Reduced Prices in the East

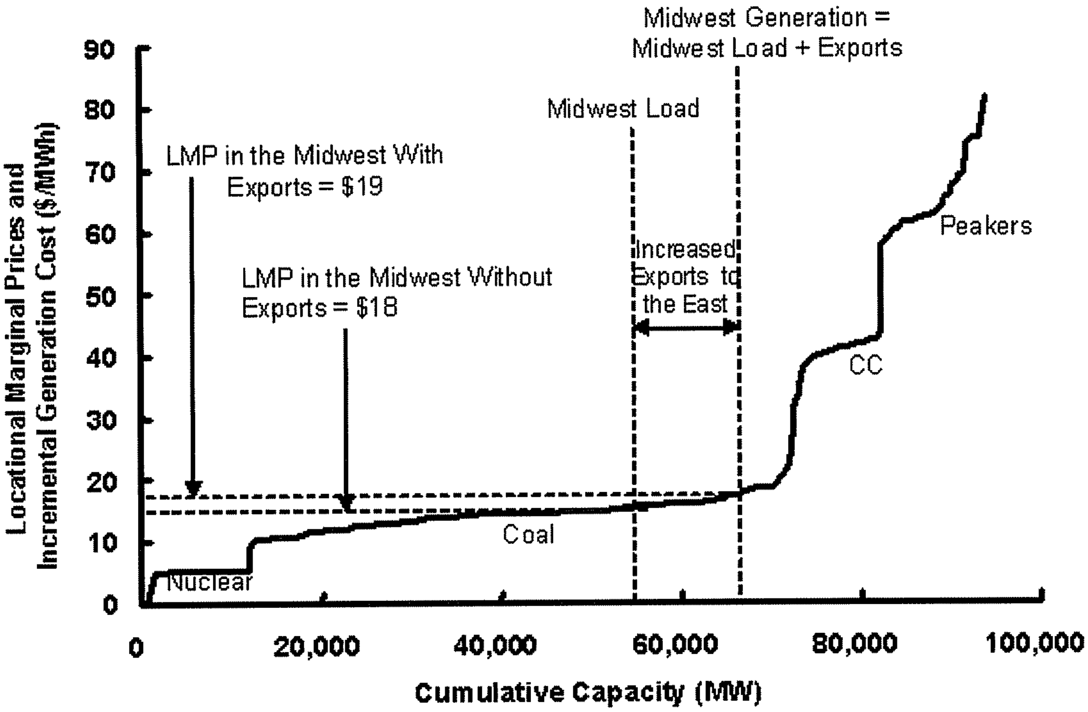


Source: Cambridge Energy Research Associates.
31204-21

Prices would be higher in the Midwest, because the additional flows to the East would be generated by the marginal generators, which have higher-costs. The lower-cost generators in the Midwest were used to serve Midwest load and a lower level of exports to the East. Hence, the increased flows to the East would be provided by higher-cost generators in the Midwest as shown in Figure 6.

Figure 6

Elimination of Wheeling Rates Results in Increased Prices in the Midwest



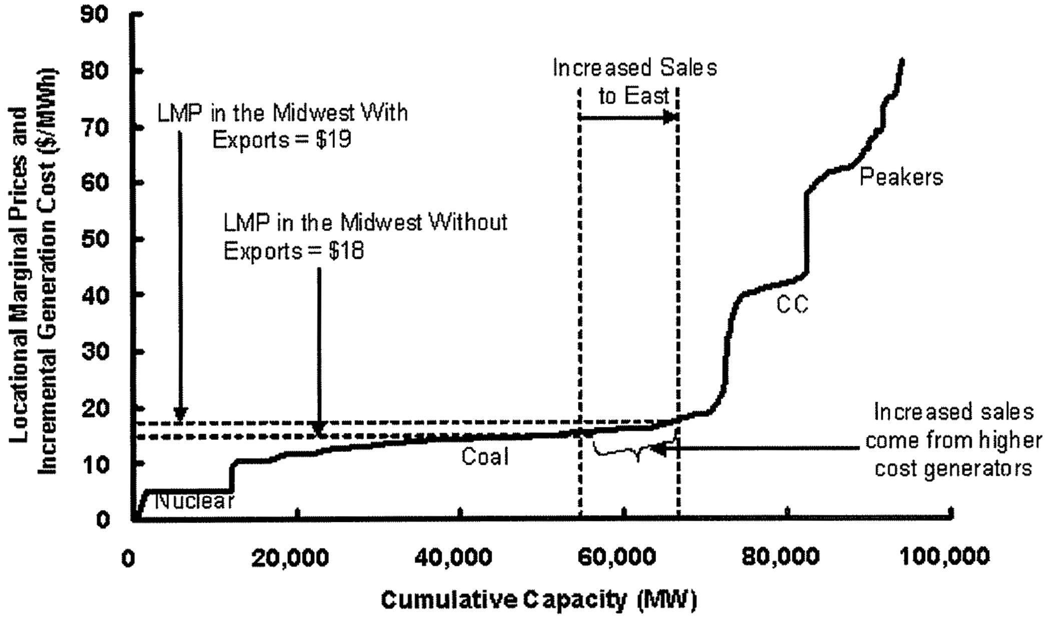
Source: Cambridge Energy Research Associates.
31204-22

Increased Margins on Off-system Sales for AEP

This analysis finds that AEP would earn additional margins from off-system sales, if wheeling rates were eliminated. This is the net effect of three factors. First, there would be increased off-system sales. Second, the sales would be at higher prices. Third, the average generation cost would be somewhat higher because the increased generation would come from the marginal higher-cost generators (see Figure 7).

Figure 7

Elimination of Wheeling Rates Results in Increased Off-system Sales for AEP



Source: Cambridge Energy Research Associates.
31204-23

The magnitude of these increased margins is provided in the testimony of Mr. Baker.

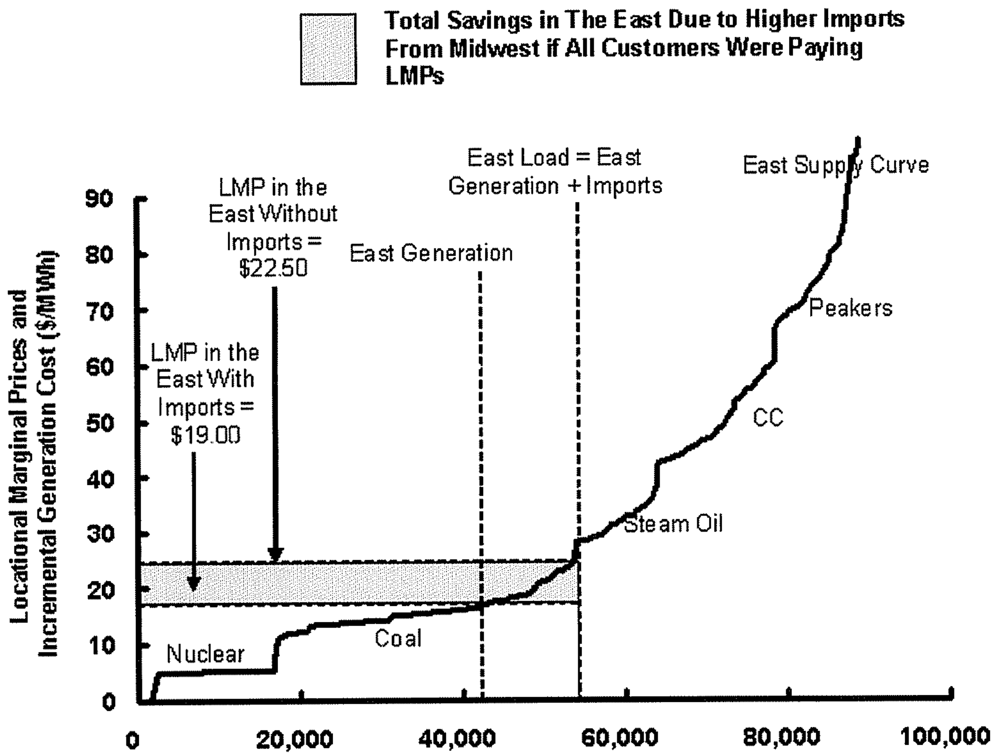
Effect on Participants in PJM and DVP

Participants in PJM and Dominion would benefit, if wheeling rates were eliminated. How much they would benefit depends on whether they are paying LMPs (in competitive retail markets) or average generation costs (where the retail energy rate is still regulated).

The participants that pay LMPs would be better off because LMPs would be lower (see Figure 8).

Figure 8

Total Savings in the East with LMPs



Source: Cambridge Energy Research Associates.
31204-24

These savings would exceed $100 million per year. (See Table 6, in which negative numbers reflect savings.)

Table 6

Change in Wholesale Energy Costs
If All Particpants Pay LMPs
(2002$ millions)

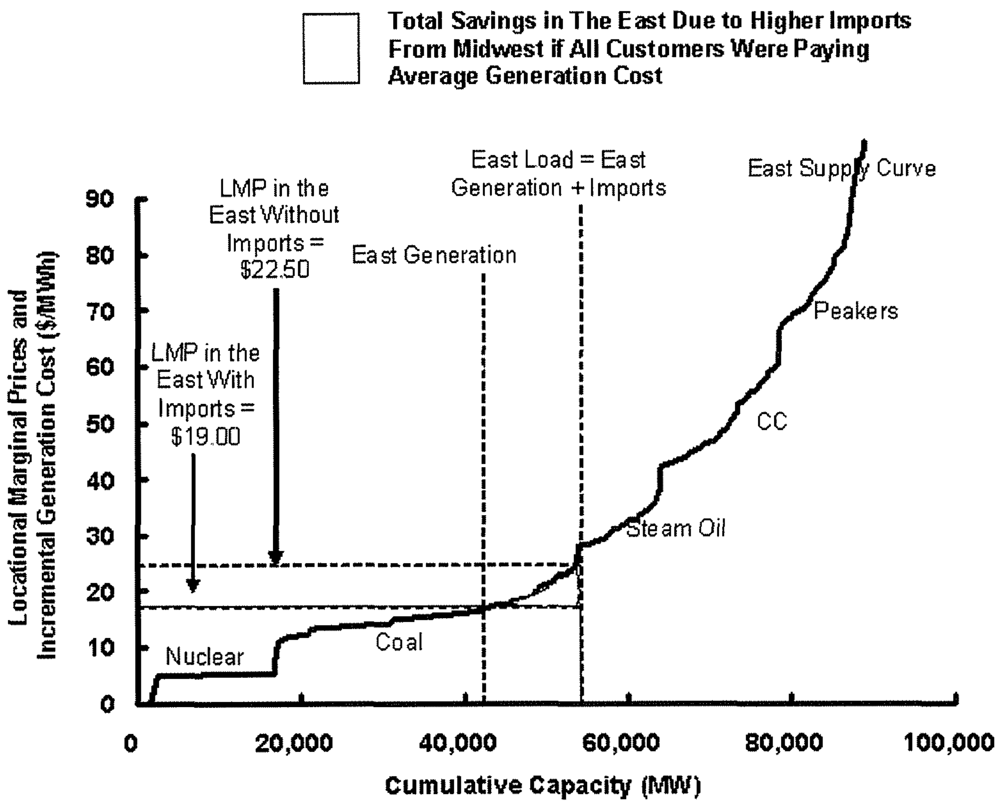
Region	2004	2006	2008
PJM	(162)	(114)	(106)
DVP	(83)	(82)	(82)

Source: Cambridge Energy Research Associates

The participants that pay average generation costs would benefit because average generation cost would be lower as a result of cheaper imports from the Midwest (see Figure 9).

Figure 9

Total Savings in the East with Average Generation Cost



Source: Cambridge Energy Research Associates.
31204-25

The savings from decreased generation costs are lower than from decreased LMPs. For the participants paying LMPs, the reduced LMP is applied to the entire load. For the participants paying average generation costs, the savings result only from the lower-cost off-system purchases that replace higher-cost own generation.

The decreased generation costs are shown in Table 7, in which negative numbers reflect savings.

Table 7

Change in Energy Costs If All Customers Pay Average Generation Costs
(2002$ millions)

Region	2004	2006	2008
PJM	(40)	(31)	(32)
DVP	(32)	(28)	(20)

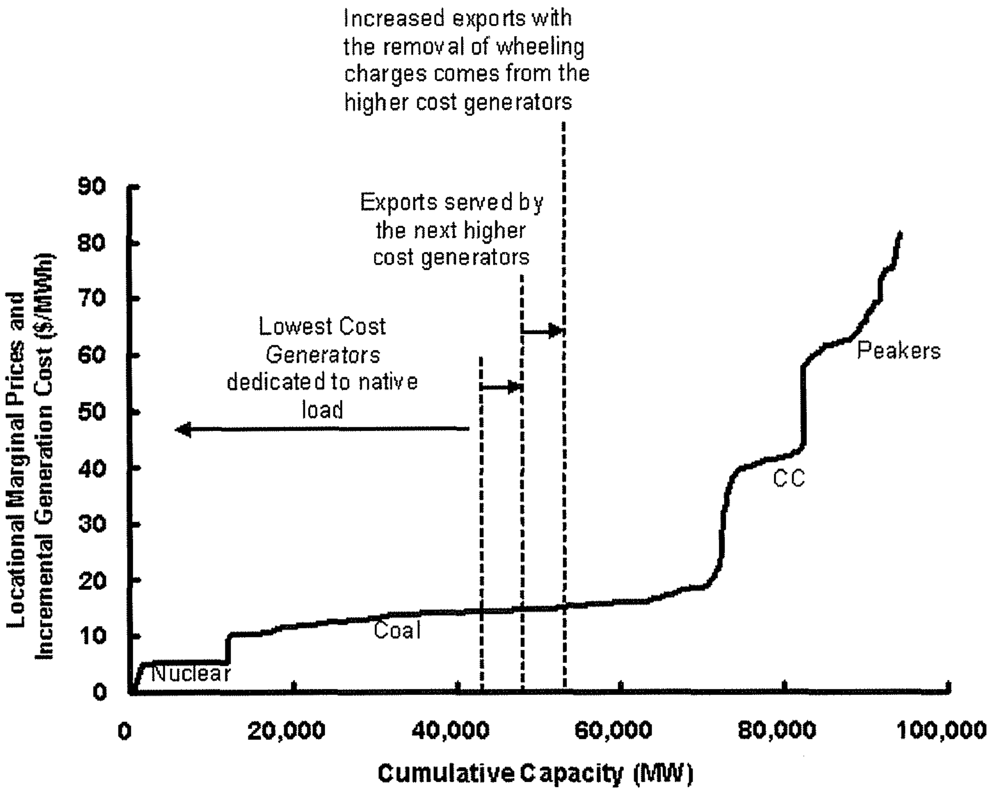
Source: Cambridge Energy Research Associates

Many PJM participants currently buy from competitive retail markets, whereas nearly all Dominion Virginia Power customers have not elected to purchase from an alternate supplier, and are subject to capped rates.

AEP customers would also benefit. They would continue to pay average generation costs with the least-cost generation allocated to AEP customers and the highest-cost generation allocated to off-system sales (see Figure 10).

Figure 10

Impact on AEP of LMPs Resulting from Increased Exports to the East



Source: Cambridge Energy Research Associates.
31204-26

Hence, there would be no direct effect on the cost of the generation used to serve AEP loads. However, the increased margins on off-system sales would reduce AEP's cost of service. Mr. Baker will testify to the magnitude of this effect.

If AEP joins PJM, AEP would be allocated financial transmission rights (FTRs) to hedge any congestion between its power plants and its loads. This is discussed by Mr. Baker.

5. Qualitative Issues

These findings must be qualified by the following discussion of several factors.

Allocation of Administrative Costs

The costs and benefits discussed above do not include the allocation of PJM administrative costs to its members. If the allocation to AEP were too high, the net benefits to AEP customers could be eliminated. The impacts of administrative costs are addressed in Mr. Baker's testimony.

Recent FERC Order

Recently, FERC has proposed that all wheeling rates be eliminated for transmission transactions within the MISO/PJM region and the former Alliance companies including AEP, regardless of RTO membership. Hence, this report simultaneously assesses the effects of eliminating wheeling rates, whether these rates are eliminated by AEP joining PJM or by FERC order.

Reliability Benefits

Reliability is an additional benefit from joining PJM. The PJM use of LMPs and security constrained unit commitment and dispatch is more reliable than other approaches, such as flow gates and transmission loading relief requests (TLRs) currently used in the Midwest. LMPs are affected by transmission conditions, and LMPs provide the proper incentives to manage congestion when a transmission problem occurs. If a transmission problem occurs, the LMPs for the generators that need to reduce generation would be low, and the LMPs for the generators that need to increase generation would be high. Further, PJM monitors transmission capacity in real time and can control generator output in real time to solve a transmission problem in real time. This is more reliable than the current Midwest approach using flow gates and TLRs without direct control over generator output.

The reliability of AEP's system in southwest Virginia would improve because PJM would be able to coordinate security-constrained dispatch and congestion management across Allegheny Power, Virginia Power (if it also joined PJM), and AEP in Virginia and West Virginia. Accordingly, PJM could improve congestion management on the critical Kanawha – Matt Funk 345 kilovolt (kV) constraint.

Coordinated operation of the transmission grid over a wider area would result in enhanced reliability of AEP's Eastern interface, as the PJM system operators would have control over more resources in a broader geographic area. The eastern interface with DVP and APS would be eliminated.

Further, PJM would coordinate the operation of the larger PJM with any other RTO in the Midwest. This should improve the reliability of the entire Midwest over the current situation.

Market Efficiency

Similarly, establishing a transparent and efficient PJM-type market over a broader geographic area would increase market efficiency in both daily unit commitment and in hourly energy flows. Conducting security-constrained unit commitment over a broader geographic area would help improve market efficiency. Also, eliminating the current cumbersome transmission reservation process and associated TLRs would help improve efficiency. However, current traders are quite good at finding economic transactions. Hence, it would be very hard to quantify how much more efficient a PJM-type market would be over the current less-efficient market design.

Further, market efficiency would be improved in the Midwest if the two RTOs develop fully compatible market designs and procedures or if there were a single RTO in the Midwest.

Regional Planning

PJM has developed a regional planning process that works to identify needed transmission enhancements. Hence, regional planning across AEP's eastern interface would improve if AEP joined PJM.

Capacity Prices

PJM has a capacity market for its participants.. The ECAR region does not have a capacity market. However, because of ample supply of capacity in ECAR and PJM at present and in the foreseeable future, capacity prices in the Midwest will be approximately the same as in PJM.

Ancillary Services

PJM operates markets for spinning reserves and regulation service for its original eastern region. However, it does not have such a market for its current western portion - Allegheny Power System (APS), since APS, being alone in PJM West would have market power in its region. Initial expectations are that ancillary services will be provided on a cost basis in the PJM West region in the foreseeable future. Hence, AEP will continue to provide these services under cost of service regulation. There would be no change.

TVA

We assumed AEP would eliminate its wheeling rates with TVA as well as with PJM and the rest of the Midwest. This is CERA's best judgment. If we had not made this assumption, the apparent benefits of joining PJM would have been slightly greater, since AEP would have had additional low-cost generation to export to the East.

Uncertainties

The numerical findings reported herein depend on the input assumptions and the structure of the GE-MAPS model. The participants of CERA's *Grounded in Reality* Multi-client Study reviewed these inputs carefully.

The GE-MAPS model is structured extremely well to assess the effects of eliminating wheeling rates on transmission flows in the presence of material transmission constraints.

But the magnitude of the forecasted savings can be affected by the inputs. Higher oil and gas prices would increase the price differentials between the regions. Conversely, lower oil and gas prices would decrease the price differentials between the regions.. Increased transmission capacity from the Midwest into the East would reduce the price differentials between regions, and vice versa. But the magnitude of the savings of eliminating wheeling rates would probably not be materially affected, if more transmission capacity added. The savings would be realized only when the wheeling rate was inhibiting the flow. Possibly, more flows would be inhibited with lower oil and gas prices and with increased transmission capacity, and vice versa. But these are probably minor effects.

On the other hand, the magnitude of the savings would be affected by the assumed wheeling rate. The higher the rate, the higher the savings of eliminating it, and vice versa.

Overall, we think the savings estimates provided herein reflect well the nature and order of magnitude of the savings that would result from eliminating wheeling rates.

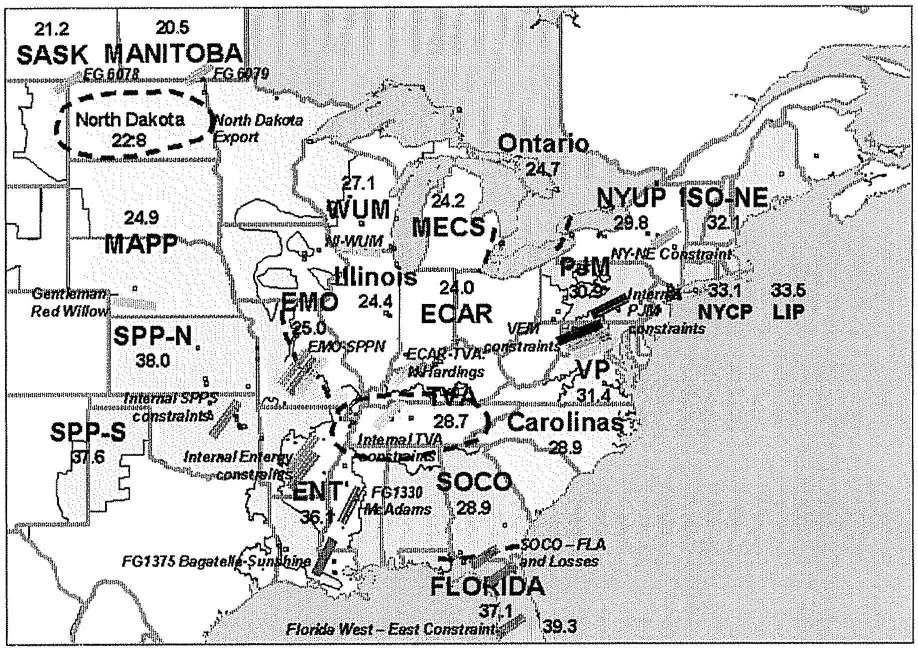
Appendix A: *Grounded in Reality* and Key Input Assumptions

Overview of Results

As shown in Figure A.1, the marginal prices in the Midwest are much less than elsewhere because transmission constraints inhibit the flow of low-cost power from the Midwest to the higher cost regions in the East, West, and South.

Figure A.1

Major Interregional Transmission Constraint in the Eastern Interconnect
Price Forecast for 2010
(2002$/MWh)



Source: Cambridge Energy Research Associates and Platts Power Map®
31204-27

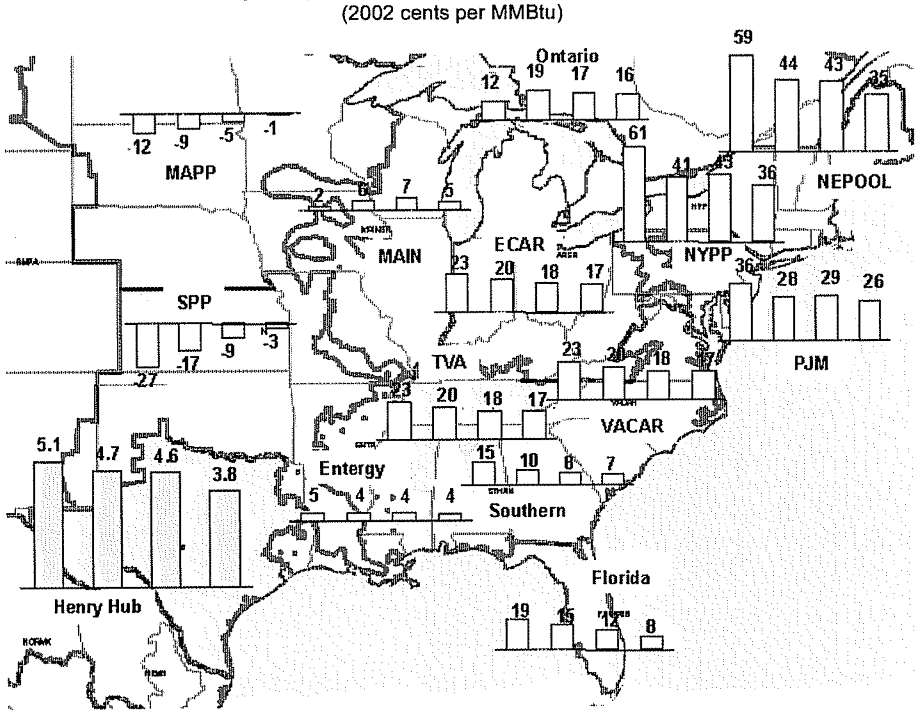
Fuel Price Forecast

The inputs to this study were carefully reviewed and approved by the study participants, who are listed in the appendix.

One of the key inputs is the fuel price forecasts. These reflected CERA's best judgments at the time the study was initiated. Figure A.2 shows the basis differentials utilized for each area of the Eastern Interconnect with Henry Hub pricing as the basis.

Figure A.2

Natural Gas Price Forecast: 2004, 2006, 2008, and 2013
Henry Hub (2002 dollars per MMBtu) Basis Differentials
(2002 cents per MMBtu)

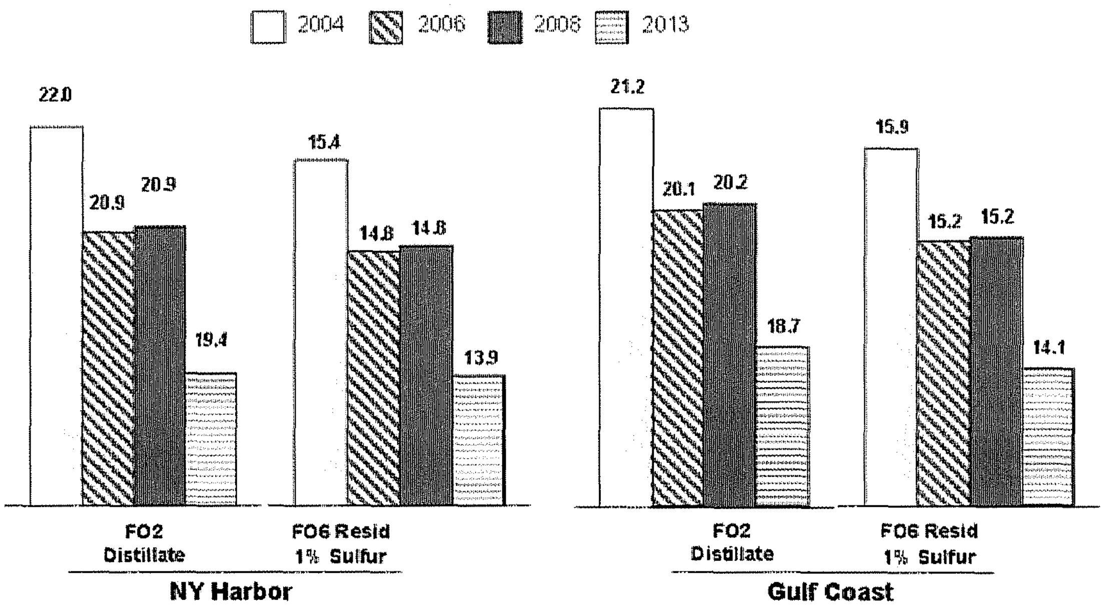


Source: Cambridge Energy Research Associates
and Platts Power Map®
31204-28

Figure A.3 indicate the difference in oil prices by region by year.

Figure A.3

Oil Price Forecast
(2002 dollars per barrel)

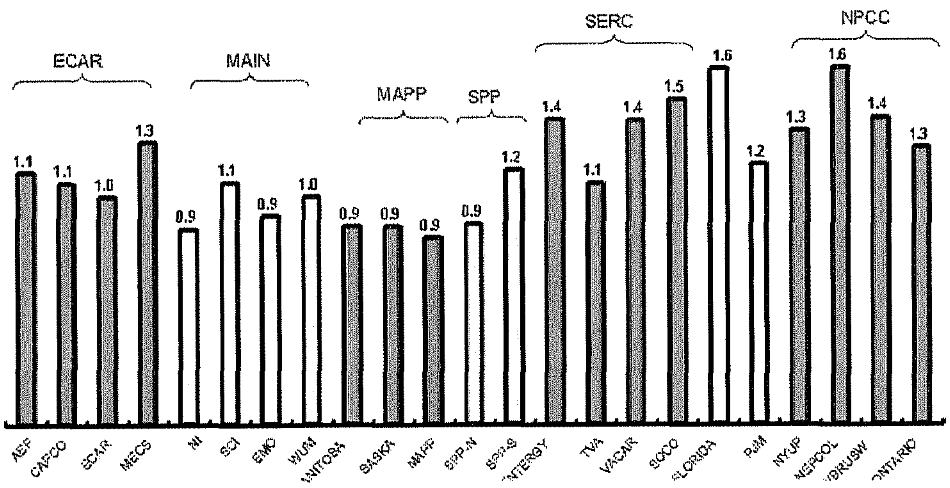


Source: Cambridge Energy Research Associates
31204-29

These are important because they affect the level of regional prices in the east. The higher these price forecasts, the greater the advantage of transmitting relatively low-priced electricity from the low-cost Midwest to the high-cost regions, including the East (see Figure A.4).

Figure A.4

Regional Average Delivered Coal Prices for 2004
(2002 dollars per MMBtu)



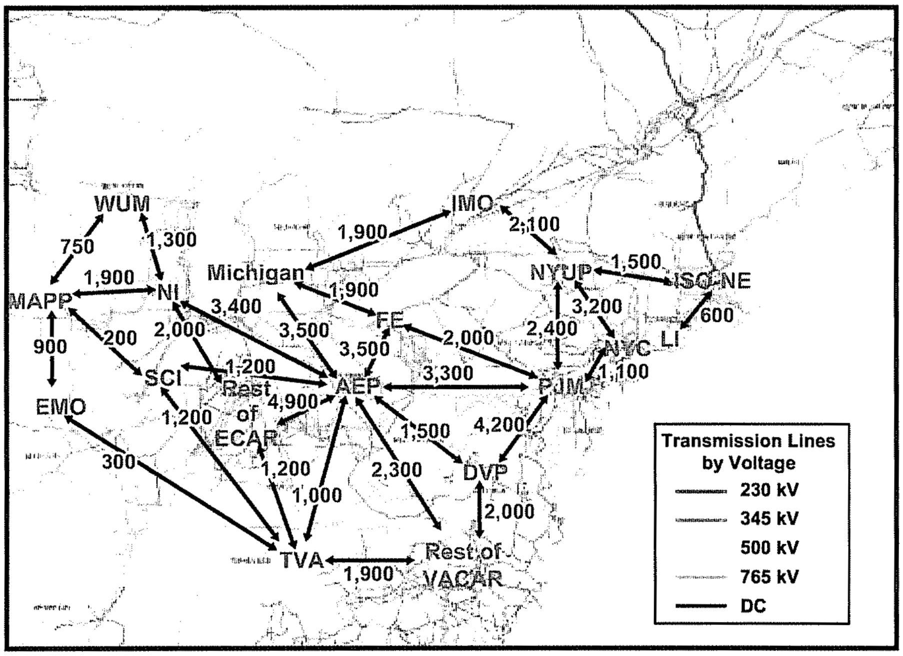
Source: Cambridge Energy Research Associates.
Note 1: Price of coal originating in Powder River Basin and Illinois Basin is assumed to decline at 1% real annually. All other coal prices are assumed to be constant in real terms through the study period.
Note 2: Prices are regional averages derived from delivered coal price forecast for each power plant
31204-30

Transfer Capability and Wheeling Charge

Transmission constraints are specified for individual lines or groups of lines. This database is proprietary to CERA, but the approximate effects of these individual constraints are summarized in Figure A.5 and Table A.1.

Figure A.5

Transfer Capabilities: Midwest and Northeast



Source: Cambridge Energy Research Associates and Platts Power Map®
31204-15

Table A.1

Pool Definition for Total Transfer Map

Region	Definition
MAPP	Mid-Continent Area Power Pool
WUM	Wisconsin and Upper Michigan
EMO	Eastern Missouri sub-region of MAIN – Ameren
NI	Commonwealth Edison control area
SCI	All of Illinois other than NI
FE	First Energy – ECAR
AEP	American Electric Power East
Rest of ECAR	All of ECAR other than AEP, FE and Michigan
TVA	Tennessee Valley Authority
DVP	Dominion Virginia Power
Rest of VACAR	Carolinas
PJM	PJM and current PJM West (Allegheny and Duquesne)
NYC	New York City
LI	Long Island
NYUP	New York Control Area other than NYC and Long Island
ISO-NE	All of former NEPOOL control area
IMO	All of former Ontario Hydro control area

Source: Cambridge Energy Research Associates

Two scenarios were assessed:

- Scenario A in which wheeling rates were assumed to be eliminated between PJM and the Midwest, including AEP, and
- Scenario B in which the existing wheeling rates were not eliminated

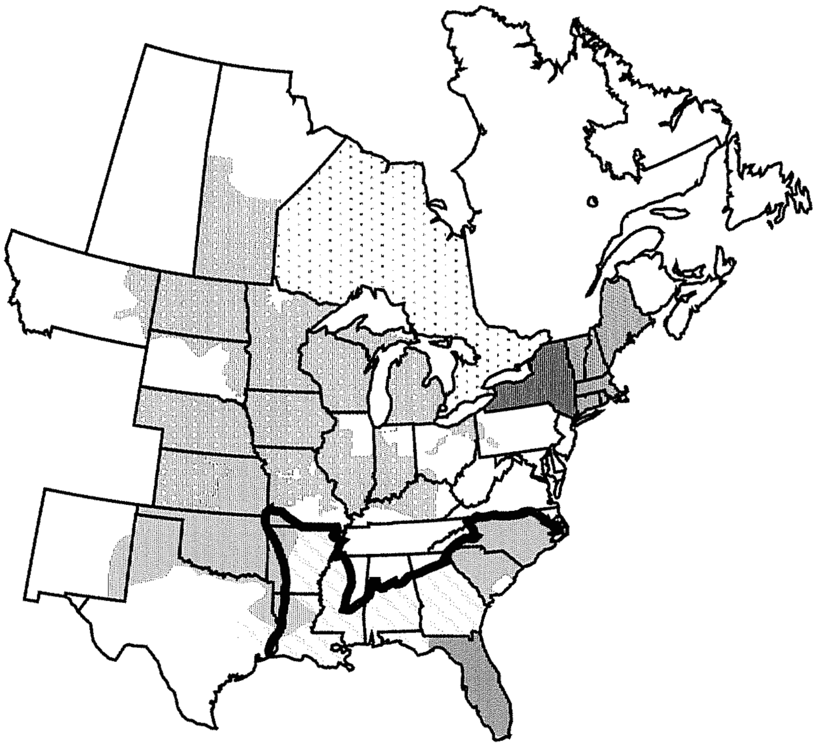
Hence, the costs and benefits of eliminating wheeling rates can be measured as the difference between Scenarios A and B.

In Scenario A, there are no wheeling rates between PJM, Dominion, AEP, NY, New England, TVA, SPP, and the rest of the Midwest. However, it was assumed that the Southeast would retain wheeling rates between themselves and the rest of the Eastern interconnect. Hence, we assumed that there would be wheeling rates between Dominion and the utilities to the south, between TVA and the utilities to the south and the Carolinas, and between Entergy and both Ameren and the Southwest Power Pool (SPP). This is the way CERA expects the wheeling rate situation to work out (see Figure A.6).

Figure A.6

In Scenario A, the Only Wheeling Charges are In, Out, and Through the South

(defined by black curve)

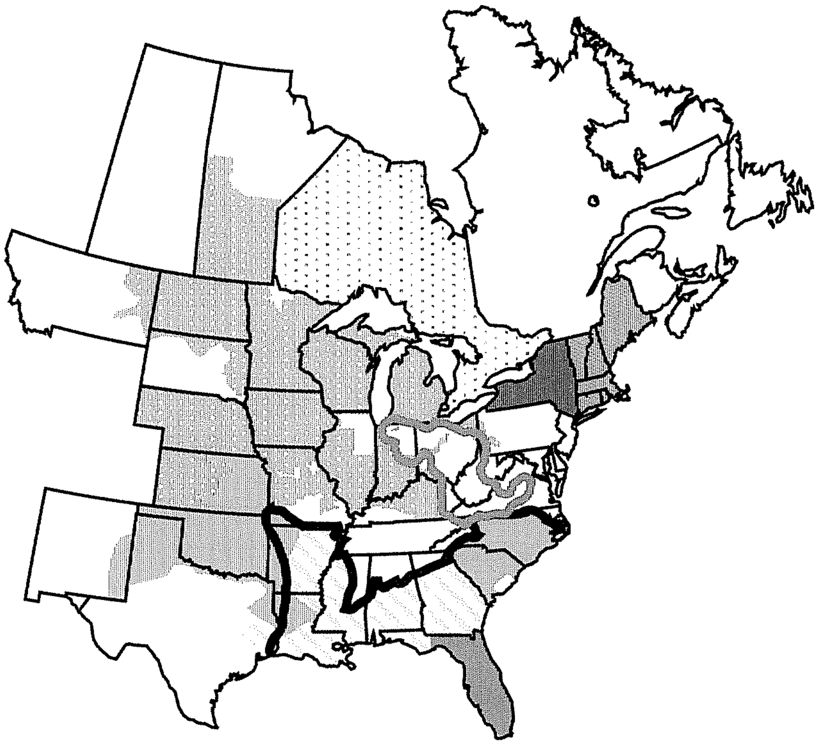


Source: Cambridge Energy Research Associates
31204-18

The second scenario is the same as the first except that there are wheeling rates between AEP and all of its direct connects (see Figure A.7).

Figure A.7

In Scenario B, there are Wheeling Charges In, Out, and Through the South and also AEP
(defined by red curve)



Source: Cambridge Energy Research Associates.
31204-18

Allowance Price

Table A.2

SO_2 Allowance Price Forecast
(2002 dollars per ton)

Year	Allowance Price
2004	176
2006	163
2008	138
2013	138

Source: American Electric Power.

Table A.3

NO_X Allowance Price Forecast
(2002 dollars per ton)

Year	Allowance Price
2004	2,617
2006	2,491
2008	2,371
2013	2,371

Source: American Electric Power.

Supply/Demand Balance

Table A.4

Pool Load Forecast: 2004–08

Pool	Coincident Peak 2004 (MW)	Coincident Peak 2004–08 Growth Rate	Net Energy for Load 2004 (GWh)	Net Energy for Load 2004–08 Growth Rate
ECAR	90,031	1.70%	505,792	1.70%
MAIN	54,028	1.80%	276,157	1.90%
MAPP	29,109	2.10%	158,736	1.90%
MAPP Canada	6,937	1.70%	40,377	1.90%
Entergy	28,627	2.40%	147,326	1.70%
SPP	40,784	2.40%	205,504	1.70%
Southern	47,250	1.80%	224,192	1.00%
TVA	30,295	1.80%	171,881	1.40%
FRCC	43,753	1.80%	209,246	1.50%
VACAR	58,869	1.80%	314,937	1.50%
PJM[1]	65,950	2.00%	356,065	1.00%
NYCA[2]	32,722	1.60%	165,740	1.90%
ISO-NE	24,374	1.40%	132,779	2.30%
New Brunswick	3,236	1.20%	16,111	1.90%
IMO	24,014	1.20%	154,370	1.90%

Source: American Electric Power.

Note 1: APS load is part of PJM.

Note 2: Assumes that Rockland Electric is part of NYCA.

Table A.5

AEP Peak Load Forecast

(megawatts)

Year	AEP Internal Load	Total AEP Connected Load
2004	20,307	23,492
2005	20,859	24,124
2006	20,381	23,714
2007	20,765	24,157
2008	21,902	25,368

Source: American Electric Power.

Table A.6

AEP Net Energy for Load Forecast

(gigawatt-hours)

Year	AEP Internal Load	Total AEP Connected Load
2004	117,275	136,772
2005	119,949	139,922
2006	121,987	142,449
2007	124,281	145,129
2008	126,305	147,537

Source: American Electric Power.

Table A.7

Planned Capacity Additions

(megawatts)

	2002			2003			2004			2005			
Pool	CC	CT	Other	CC	CT	Other	CC	CT	Other	CC	CT	Other	Total
ECAR	2,261	4,053	0	5,499	1,110	0	0	0	268	700	0	0	**13,891**
MAIN	1,610	2,518	80	0	450	0	600	0	0	0	0	0	**5,258**
Mapp - Canada	0	100	228	0	0	0	0	0	0	0	0	0	**328**
MAPP	315	50	225	126	670	0	0	0	0	0	0	400	**1,786**
SPP	2,541	321	0	2,898	550	0	0	0	0	0	0	0	**6,310**
Entergy	5,479	640	0	5,135	0	0	720	0	0	564	0	0	**12,538**
Southern	6,066	1,549	0	4,888	624	0	0	0	0	0	0	0	**13,127**
TVA	3,020	1,960	0	900	0	0	0	0	0	0	0	0	**5,880**
FRCC	3,020	2,619	600	3,460	0	0	1,295	0	0	0	0	0	**10,994**
VACAR	950	300	0	920	1,140	0	875	0	0	0	0	0	**4,185**
PJM	3,362	2,224	45	2,580	333	0	1,300	0	520	1,186	0	0	**11,550**
NYCA	0	717	0	1,095	0	0	2,169	0	0	250	0	272	**4,503**
ISO-NE	3,167	0	0	3,000	0	0	0	0	0	0	0	0	**6,167**
IMO	650	0	0	0	0	2,015	0	676	0	0	0	0	**3,341**
Total	**33,041**	**17,051**	**1,178**	**29,801**	**4,877**	**2,015**	**6,959**	**676**	**788**	**2,700**	**0**	**672**	**99,758**

Sources: Cambridge Energy Research Associates, Platts NewGen® copyrighted database.

Table A.8

Cumulative Wind Additions

(megawatts)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
ECAR1	405	405	420	435	450	465	480	495	510	525
ENTERGY	0	0	0	0	0	0	0	0	0	0
FRCC	0	0	0	0	0	0	0	0	0	0
MAIN	168	305	430	481	570	583	667	751	835	919
MAPP Canada	0	0	0	0	0	0	0	0	0	0
MAPP	234	930	1047	1169	1295	1626	1763	1900	2037	2174
New Brunswick	0	0	0	0	0	0	0	0	0	0
ISO-NE	58	453	585	724	910	952	994	1036	1078	1120
NYCA	75	290	592	917	1234	1575	1930	2285	2640	2995
IMO	0	0	60	60	60	60	60	60	60	60
PJM	110	110	165	224	283	345	410	475	540	605
Southern	0	0	0	0	0	0	0	0	0	0
TVA	0	0	0	0	0	0	0	0	0	0
VACAR	0	0	0	0	0	0	0	0	0	0
Total	**1049**	**2492**	**3297**	**4008**	**4800**	**5603**	**6300**	**6997**	**7694**	**8391**

Sources: Cambridge Energy Research Associates, Platts NewGen® copyrighted database.

Table A.9

Cumulative Biomass, Landfill, and Hydro Additions

(megawatts)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
ECAR	155	159	176	193	210	227	244	261	278	295
ENTERGY	0	0	1	2	3	4	5	6	7	8
FRCC	0	3	6	9	12	15	18	21	24	27
MAIN	18	24	31	34	39	40	44	48	52	56
MAPP Canada	0	0	0	0	0	0	0	0	0	0
MAPP	112	365	423	484	547	713	781	849	917	985
New Brunswick	0	0	0	0	0	0	0	0	0	0
ISO-NE	5	99	128	158	199	208	217	226	235	244
NYCA	0	156	319	494	665	849	1,040	1,122	1,204	1,286
IMO	0	0	0	0	0	0	0	0	0	0
PJM	8	76	123	173	223	276	331	386	441	496
Southern	0	9	14	19	24	29	34	39	44	49
TVA	0	28	28	28	28	28	28	28	28	28
VACAR	18	18	24	30	36	42	48	54	60	66
Total	**316**	**937**	**1,272**	**1,623**	**1,984**	**2,429**	**2,789**	**3,040**	**3,291**	**3,542**

Sources: Cambridge Energy Research Associates, Platts NewGen® copyrighted database.

Table A.10

Retirements over the Study Horizon

(megawatts)

	2002	2003	2004	2005	2006–13	Total
ECAR	502	622	0	0	210	**1,124**
MAIN	0	179	0	0	3	**179**
Mapp - Canada	0	0	0	0	12	**0**
MAPP	0	0	0	0	39	**0**
SPP	0	0	0	0	0	**0**
Entergy	0	0	170	0	547	**170**
Southern	379	0	0	0	0	**379**
TVA	0	0	0	0	199	**0**
FRCC	1,461	1,083	730	589	665	**3,863**
VACAR	150	0	90	88	0	**328**
PJM	235	196	0	447	223	**878**
NYCA	45	400	836	1	24	**1,282**
ISO-NE	72	1,599	0	0	28	**1,671**
IMO	0	0	0	1,148	36	**1,148**
Total	**2,844**	**4,079**	**1,826**	**2,273**	**1,984**	**11,022**

Sources: Cambridge Energy Research Associates, Platts NewGen® copyrighted database.

Table A.11

Target Reserve Margin
(percent of peak load)

Pool	Target Reserve Margin (percent)
AEP	15%
First Energy - ECAR	15%
Michigan	15%
Rest of ECAR	15%
E. Missouri	15%
SC Illinois	15%
N. Illinois	15%
WUM	15%
MAPP	15%
Mapp-Canada	15%
SPP-N	15%
SPP-S	15%
Entergy	15%
TVA	15%
Southern	15%
FRCC	19%
VACAR	15%
PJM	17%
Long Island	-7%
New York City	-20%
NYCA	18%
ISO-NE	18%
IMO	15%

Sources: Cambridge Energy Research Associates, Platts NewGen® copyrighted database.

Please see associated document for CERA's *Grounded in Reality: Bottlenecks and Investment Needs of the North American Transmission System* Multiclient Study prospectus.

Grounded in Reality: Bottlenecks and Investment Needs of the North American Transmission System

Multiclient Study Preliminary Highlights
by Gilbert M. Rodgers and Hoff Stauffer, *Coleaders*,
CERA Electric Transmission Service

October 2003

CERA®

INTRODUCTION

Grounded in Reality is a CERA organized and sponsored Multiclient Study conducted with over 30 participating organizations from the transmission industry and government/regulatory groups. There are three sequenced phases to the project corresponding to the major transmission regions in North America:

- Eastern Interconnect
- Western Interconnect
- Electric Reliability Council of Texas (ERCOT)

The Eastern Interconnect phase of the project is approaching completion—the final workshop was held in Annapolis, Maryland, on October 1, 2003. The Western Interconnect phase is at the midpoint, with the second workshop held in Portland, Oregon, on October 15, 2003, and the third and final workshop scheduled for January 2004 in San Diego. The third phase for ERCOT will be initiated with a kick-off workshop on February 13 in Houston, Texas, and the final workshop will be held in April 2004.

Grounded in Reality assesses what transmission bottlenecks currently exist, might arise, or might continue over a 15-year period, with major attention focused on 2010. Then, for the significant bottlenecks, the study analyzes economic solutions, which include

- proper siting of new generation to relieve the bottlenecks
- new transmission investments where the benefits of the relieved congestion exceed the costs of the new transmission
- nothing, where the costs of the least expensive solution would exceed the benefits

The new transmission investments options include

- upgrading specific transmission facilities
- new technologies such as Flexible Alternating Current Transmission Systems (FACTS)
- adding entirely new AC lines
- adding DC lines

The study is being conducted by CERA's Transmission Team under the technical direction of Hoff Stauffer and commercial leadership of Gilbert M. Rodgers. The team utilizes CERA's proprietary version of the GE-MAPS electricity market simulation model, with inputs from CERA's other services.

PRELIMINARY HIGHLIGHTS OF EASTERN INTERCONNECT PHASE

- There is, of course, congestion within geographic regions, but the largest and most serious congestion is between regions.
- In the Eastern Interconnect, 32 interregional constraints have been identified, resulting in total congestion costs of $1.6 billion in 2010.
- Major congestion exists between
  - Mid-America Interconnected Network (MAIN)/East Central Area Reliability Coordination Agreement (ECAR) and the PJM Interconnection
  - MAIN/ECAR and Tennessee Valley Authority (TVA)
  - MAIN/ECAR and Southwest Power Pool (SPP)
  - Mid-Continent Area Power Pool (MAPP) and SPP
  - TVA/Southern and Entergy
  - Southern and Florida
- In addition, the study has identified about 70 intraregional congestion constraints (many of them relatively easily solved) that result in $1.2 billion in congestion costs in 2010. These are localized primarily in the NYISO, PJM, ECAR, Wisconsin and upper Michigan, Entergy, and SPP regions.
- Current research is developing solutions and conducting benefit-costs studies for major transmission constraints.
- Some of the options being consider are
  - additional lines to relieve the VACAR–ECAR–MAAC (VEM) constraints between ECAR, PJM, and Northern Virginia
  - a high-voltage line from AEP's 765 kilovolt system to TVA
  - enhancements on key constraints into
    - Entergy
    - Florida
    - SPP from both the north and the east
    - DC options into New York City
- The complete study—available to study participants—will show all of the constraints, the economically viable solutions, the impacts these solutions will have on the transmission network, and the needs for investment.

PRELIMINARY HIGHLIGHTS OF WESTERN INTERCONNECT PHASE

- The Western Interconnect findings are similar: major congestion is between geographic regions, rather than within them.
- Twenty-seven interregional constraints have been identified, resulting in $1.5 billion in annual congestion costs in 2010 (constant 2002 dollars).
- The most major constraints are
  - from Northern California to Southern California
  - from Arizona and Nevada to Southern California and particularly San Diego
  - from Alberta to British Columbia
  - from Wyoming to Colorado and the Pacific Northwest
- Potential solutions to be evaluated are
  - enhancing Path 26 from Northern California to Southern California
  - various enhancements from Palo Verde into Devers and into San Diego
  - enhancements for Southern Alberta into British Columbia and then into Washington
  - a DC line from Fort McMurray to Celilo (Big Eddy)
  - various enhancements to transmit low-cost Powder River Basin coal to the south and west
- In contrast, only 13 intraregional constraints have been identified, and these are particularly important in Southern California.

OTHER PRELIMINARY HIGHLIGHTS

- High natural gas prices, if sustained over the longer term, will have major implications for transmission requirements, especially in the East. For example, high gas prices create greater value for transmission enhancements that
    - move coal-fired energy to markets with lots of oil and gas capacity
    - enable wind generation to get to markets with higher prices
    - enable cogeneration associated with oil sands development to get to markets with much higher prices
- Sensitivity analyses indicated that in addition to gas price responses, the congestion bottlenecks and locational prices are highly sensitive to the level of hydro generation in the western states, to wheeling charges for moving energy across a transmission system, and to a carbon tax, which would affect the amount of coal generation.
- The good news is that in the Eastern Interconnect there appears to be viable and relatively economical ways of relieving interregional congestion. Taken together, these enhancements would cost approximately $3 billion and have net benefits of about $1 billion per year in 2010, resulting in a strong, positive benefit-cost relationship.
- However, solutions may be very difficult to implement. There will be winners and losers, and the distances are great. Loads would be losers in the Midwest and winners in the East, South, and West. Conversely, generators would be winners in the Midwest and losers elsewhere. Usually, the winners and losers will be in different states and different regional transmission organizations. A regulatory framework has not yet been established to deal with such complex situations. It is Federal Energy Regulatory Commission policy that the beneficiaries should pay, but it may be difficult to gain agreement on who the beneficiaries are and whether and how the losers should be compensated. Heated deliberations are anticipated among the multitude of affected parties.

Appendix B: Overview of GE—MAPS Model

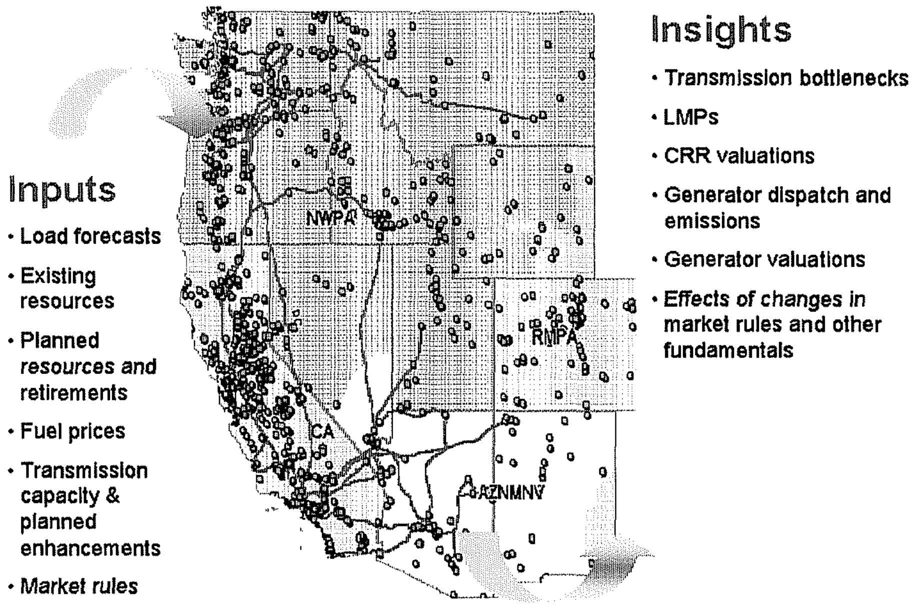
Overview

MAPS is a production cost model that simulates both the day-ahead commitment of units and the hour-by-hour dispatch of committed units to efficiently clear the market for power (see Figure B.1). In both of these steps, MAPS considers unit-by-unit costs and operating constraints, and minimizes production costs given transmission constraints.

First, this document describes how thermal units are committed and dispatched in MAPS. Then hydro scheduling and pumped storage scheduling are described.

Figure B.1

GE-MAPS Is a Production Cost Model with Excellent Representation of Transmission



Source: Cambridge Energy Research Associates
31204-31

The actual sequence of events in MAPS is

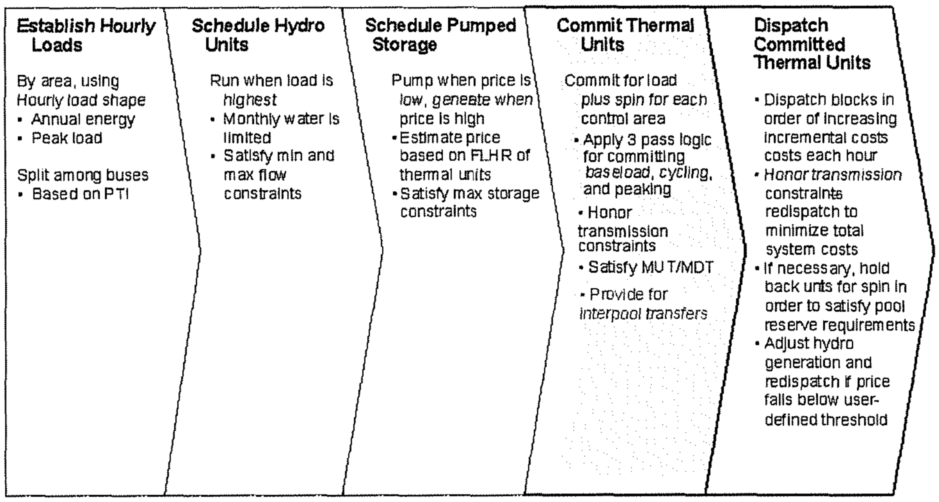
- Establish hourly loads everywhere.
- Schedule generation for hydro units. Calculate residual loads.
- Schedule pumping and generation at pumped storage units. Calculate modified loads.

- Commit thermal units for load (modified from previous step) plus spin, while accounting for transmission constraints.
- Dispatch hydro and PS according to their established schedules, and dispatching thermal units based on incremental costs while accounting for transmission constraints (see Figure B.2)

Figure B.2

GE-MAPS Simulates Both the Day-ahead Commitment and Hour-by-hour Dispatch of Committed Units

(Commitment and Dispatch in MAPS)



Source: Cambridge Energy Research Associates
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Commitment of Thermal Units in MAPS

Commitment is necessary in the real world because generators take time to ramp up. Units have to be notified to turn on in advance if they are to provide energy or ancillary services. It's the ISO's job to schedule when each unit turns on and off, so as to minimize total system costs, subject to transmission and operating constraints.

Each hour, the commitment algorithm in MAPS selects units in order of increasing average costs (dollars per MWh) over their anticipated duty cycles. This minimizes total system cost so long as the duty cycles are guessed correctly and the average costs are calculated accurately. Average cost is just total-cycle cost (including cold startup costs, variable operating and maintenance costs, fuel costs at all load levels experienced, and any additional variable bid) divided by total output. The tricky part is predicting the duty cycle for each unit. It's tricky because you can't know a unit's duty cycle until you know when it and all the other units will be committed!

One approach to commitment would be to try every possible schedule and see which has the lowest cost. That would be an intractable problem. Instead, MAPS sorts all units into first baseload, then cycling, and finally peaking duty cycles for a "three-pass" approach to commitment. Progressive sorting from least expensive/baseload duty to most expensive/peaking duty leads to a near optimum commitment because

- the cheaper units should run more than the more expensive units
- the more a unit runs, the greater the output over which the startup costs can be amortized, and the lower its average costs will be

Critical Issues During Commitment

Transmission Constraints and Contract Paths

Transmission constraints are considered in each pass of the commitment logic. Wheeling charges and losses are also considered because they are modeled as "soft" transmission constraints that can be exceeded for a small dollars per MWh hurdle.

Initially, MAPS schedules units based purely on generator economics, as if there were no transmission constraints. If the unconstrained solution violates transmission constraints, enormous overload costs are charged (hundreds of dollars per MW). MAPS then seeks to reduce these costs by rescheduling, using shift factors as a guide to which units to turn off and which to turn on. MAPS iterates until it cannot find a cheaper solution.

This kind of cost minimization simulates what would happen within an ISO, or within a power pool which has smaller control areas and which has competitive market mechanisms for allocating scarce transmission resources efficiently. However, if any contract path limits are specified, then they are honored in addition to the physical constraints on the electric transmission system. In this way, MAPS can embed an "old think" type of inefficient allocation of scarce transmission, if that better represents reality.

MUT/MDT Constraints

After going through the three passes for an entire week, MAPS honors operating constraints by turning units on for more hours, as needed. No units are turned off. As a result, many pools can typically have thousands of MW of unneeded capacity committed during off-peak hours. This is why so many units sit at or near minimum load at night.

The one tricky part is getting the beginning and the end of the week right. The next week's commitment is not yet known, so MAPS guesses that it will be identical to the beginning of the present week and fills in accordingly. At the beginning of the week, MAPS looks back at the previous week's commitment and turns on units during the wee hours of Monday morning if doing so will help prevent violation of the operating constraints. However, the previous week's commitment cannot be revised, and the constraints can be violated occasionally late on Sunday night.

Must-run Units

Some units are designated as "must-run" and can be committed instantaneously if they become the best economic option during dispatch. The capacity of these units "counts" toward load plus spin only if it gets used.

Committing for Operating Reserves

MAPS commits for load plus spin on the pool level, as described above. Then MAPS also makes sure that there is enough capacity available to the meet spin and quick-start requirements in each pool. MAPS does a sum-product over the capacities of all committed units and their maximum percent contribution in each reserve category. We have specified the maximum spin contribution to be 10 percent for all steam units and combined cycles.

So far, we have assumed that spin must be provided natively, and that it cannot be imported from other pools. We can model spin imports by shifting some of the spin requirement from the importing pool to the exporting pool. We would also have to reduce the transmission capacity of the tie lines by the amount of the spin trade, as this capacity has to be reserved in case the spinning reserve gets called up. In this way, we could represent the spin imports that we know exist in the West (into California).

Dispatch of Thermal Units

Dispatching for Load

Minimizing costs during dispatch is more straightforward than during commitment. As long as the incremental bids are monotonically increasing over the blocks available from each unit, the ISO or MAPS can minimize system costs by following the simple rule: dispatch available blocks each hour in order of increasing incremental cost. Incremental costs include incremental heat rate * fuel cost + VOM + any additional incremental bid.

Dispatch is usually done by system—MAPS finds the systemwide least-cost solution, subject to transmission constraints. This simulates efficient allocation of transmission capacity and efficient wholesale power trading between ISO's. Transmission constraints are honored as described above for commitment.

Provision of Spinning Reserves

If spin in dispatch is turned on, MAPS dispatches for load then makes sure each pool has enough spinning reserve. MAPS counts any unused hydro capacity plus the surge rating on steam units plus the unused capacity on any units that are not at full load, up to the maximum spin contribution of each unit (10 percent for all units). If there is not enough spin, MAPS starts holding back thermal units, most expensive first, until there is enough spinning reserve in each pool. As units that are inframarginal in the energy market get held back, more expensive units have to get ramp up, and the energy price rises.

Transmission constraints are not considered when units are selected for contributing spin. It is possible to have too much capacity held back in a load pocket, and very high prices or unserved energy can result. This is the so-called "LILCO-type problem." There is also the inverse problem. MAPS can fail to provide enough spin in an area, resulting in inadequate reliability. This type of problem is harder to detect because MAPS has no surprises and spinning reserve never actually has to run. We try to control both types of problems by adjusting the maximum spin contributions of critical units, and by carving the power pools into smaller pools. MAPS is then forced to provide the right amount of spinning reserve in each subpool.

Quick-start

Quick-start is never actually dispatched in MAPS because there are no load surprises or unexpected forced outages.

Hydro and Pumped Storage

Hydro and pumped storage units are scheduled before thermal units, and in a very different manner. Both types of units have to plan ahead not because of ramp time, but because they have limited "fuel." They have to manage their limited resources by anticipating what prices will be over weeks and months. Hence, it makes sense for the model to develop at least a tentative plan before the thermal units do their day-ahead commitment and hour-ahead dispatch planning.

Hydro Scheduling

Hydro units would like to spend their "fuel" during only the highest priced hours. But they don't know when those hours will be until the market has cleared. Therefore, they do the best they can by scheduling ahead of time. One month at a time, they schedule their limited monthly energy to run during the hours with the highest load. The relevant load is input by the user. It may be the native pool's load, or it may include other pools if the hydro-owners are big exporters.

Each unit is scheduled in such a way that obeys maximum and minimum flow constraints, but without honoring transmission constraints because congestion costs cannot be measured until all the thermal units run.

Pumped Storage Scheduling

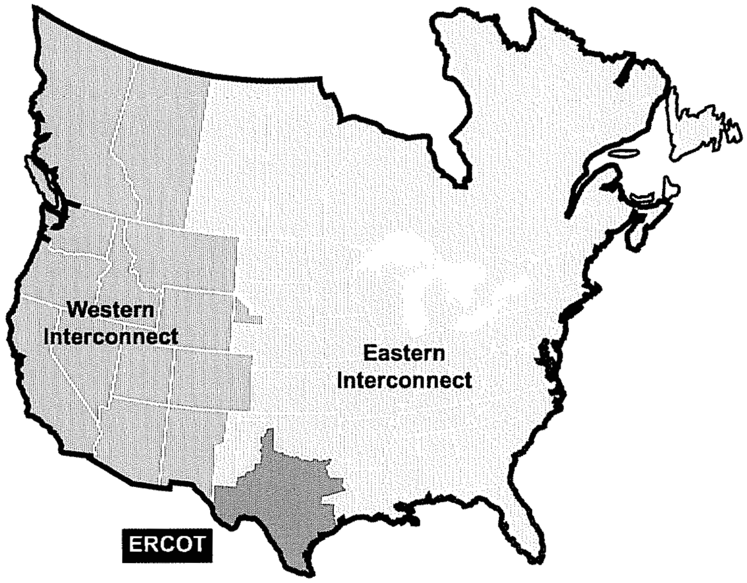
Pumped storage units have to plan ahead because they have limited storage in both the upper and lower reservoirs and because they like to start out the work week with a full upper reservoir. Over the course of the week, they flatten prices by pumping when prices are low and generating when prices are high.

Pumped storage is scheduled in several steps, none of which considers transmission constraints. First, PS units are scheduled based on economics, without regard to storage capacity. MAPS estimates the energy clearing price in every hour based on the full load average cost for every thermal unit. Then PS units are scheduled to generate in the week's highest cost hour and pump in the lowest cost hour. Then the next highest and next lowest cost hours are paired up. MAPS continues to match up generating and pumping hours as long as it can reduce the systemwide costs, net of each PS unit's pumping losses (their efficiency is around 70 percent). PS units are not scheduled to operate during the intermediate-priced hours.

Then storage constraints are addressed for each pumped storage unit individually. The hour with the greatest violation is identified (when the quantity in either the upper or lower reservoir becomes the most negative). Suppose that occurs in hour 55 for a particular unit. Then the week is split into two pieces, hours 1–55 and 56–168. The PS unit is scheduled for each piece based on economics, as described above, and then the storage constraints are checked again. If there is a violation, the sub-weeks are split again and MAPS reschedules for each piece and iterates until there are no violations. Splitting the week into sub-weeks prevents the unit from doing all it's pumping in one part of the week and all of its generating in another. The split pieces have less variability than a whole week has, and the high and low hours are not as far from each other in time (see Figures B.3–B.4).

Figure B.3

CERA Has Three Versions of MAPS: One for the Eastern Interconnect



Source: Cambridge Energy Research Associates.
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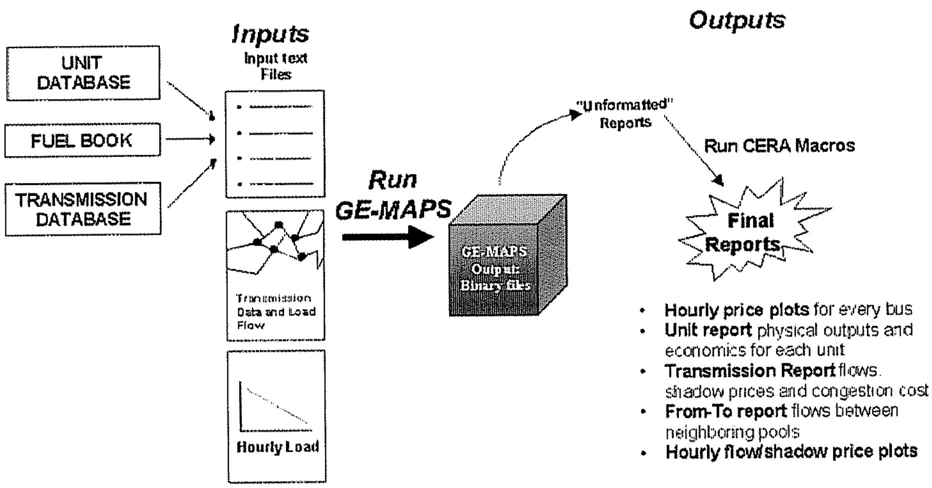
Figure B.4

CERA Has Developed a Proprietary User Front-end and Database, which Leverages CERA's Unparalleled Market Intelligence



Source: Cambridge Energy Research Associates.
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Appendix C: Outputs

Interpool Flows

Table C.1

Pool Definitions Used in Interpool Transfer Tables

Pool	Definition
NYCA	New York Control Area
PJM	PJM Interconnection
DVP	Dominion Virginia Power control area
CAR	Carolinas
PJMW	Current PJM West – Allegheny and Duquesne control areas
AEP	American Electric Power East
FE	First Energy – ECAR
MECS	Michigan Electric Coordinated System—mainly Detroit Edison and Consumer Power
ECAR	ECAR other than AEP, FE and MECS
WUM	Wisconsin and Upper Michigan
NI	Commonwealth Edison control area
SCI	All of Illinois other than NI
EMO	Eastern Missouri—mainly Ameren control area
IMO	Independent Electricity Market Operator—all of former Ontario Hydro control area

Source: Cambridge Energy Research Associates.

Table C.2

Average Hourly Interpool Flows: 2004 Scenario B
(megawatts)

From	NYCA	PJM	VP	VAC	APS	AEP	FE	ECAR	MECS	WUM	NI	SCI	EMO	OH	TOTAL
NYCA	X	(1,426)	0	0	0	0	0	0	0	0	0	0	0	(1,471)	**(2,897)**
PJM	1,426	X	177	0	(1,551)	0	(361)	0	0	0	0	0	0	0	**(309)**
VP	0	(177)	X	(414)	(466)	(590)	0	0	0	0	0	0	0	0	**(1,647)**
VAC	0	0	414	X	0	(139)	0	0	0	0	0	0	0	0	**275**
APS	0	1,551	466	0	X	(795)	(380)	0	0	0	0	0	0	0	**842**
AEP	0	0	590	139	795	X	540	(1,280)	1,564	0	(676)	325	0	0	**1,997**
FE	0	361	0	0	380	(540)	X	(66)	(74)	0	0	0	0	0	**61**
ECAR	0	0	0	0	0	1,280	66	X	37	0	(729)	159	0	0	**813**
MECS	0	0	0	0	0	(1,564)	74	(37)	X	0	0	0	0	(633)	**(2,160)**
WUM	0	0	0	0	0	0	0	0	0	X	(621)	0	0	0	**(621)**
NI	0	0	0	0	0	676	0	729	0	621	X	600	0	0	**2,626**
SCI	0	0	0	0	0	(325)	0	(159)	0	0	(600)	X	441	0	**(643)**
EMO	0	0	0	0	0	0	0	0	0	0	0	(441)	X	0	**(441)**
OH	1,471	0	0	0	0	0	0	0	633	0	0	0	0	X	**2,104**
TOTAL	**2,897**	**309**	**1,647**	**(275)**	**(842)**	**(1,997)**	**(61)**	**(813)**	**2,160**	**621**	**(2,626)**	**643**	**441**	**(2,104)**	

Source: Cambridge Energy Research Associates.

Table C.3

Average Hourly Interpool Flows: 2004 Scenario A
(megawatts)

From	NYCA	PJM	VP	VAC	APS	AEP	FE	ECAR	MECS	WUM	NI	SCI	EMO	OH	TOTAL
NYCA	X	(1,624)	0	0	0	0	0	0	0	0	0	0	0	(1,475)	**(3,099)**
PJM	1,624	X	121	0	(1,924)	0	(406)	0	0	0	0	0	0	0	**(585)**
VP	0	(121)	X	(551)	(348)	(813)	0	0	0	0	0	0	0	0	**(1,833)**
VAC	0	0	551	X	0	(243)	0	0	0	0	0	0	0	0	**308**
APS	0	1,924	348	0	X	(1,745)	(217)	0	0	0	0	0	0	0	**310**
AEP	0	0	813	243	1,745	X	1,566	(2,132)	2,683	0	(1,052)	297	0	0	**4,163**
FE	0	406	0	0	217	(1,566)	X	(87)	686	0	0	0	0	0	**(344)**
ECAR	0	0	0	0	0	2,132	87	X	80	0	(737)	156	0	0	**1,718**
MECS	0	0	0	0	0	(2,683)	(686)	(80)	X	0	0	0	0	(164)	**(3,613)**
WUM	0	0	0	0	0	0	0	0	0	X	(562)	0	0	0	**(562)**
NI	0	0	0	0	0	1,052	0	737	0	562	X	446	0	0	**2,797**
SCI	0	0	0	0	0	(297)	0	(156)	0	0	(446)	X	435	0	**(464)**
EMO	0	0	0	0	0	0	0	0	0	0	0	(435)	X	0	**(435)**
OH	1,475	0	0	0	0	0	0	0	164	0	0	0	0	X	**1,639**
TOTAL	**3,099**	**585**	**1,833**	**(308)**	**(310)**	**(4,163)**	**344**	**(1,718)**	**3,613**	**562**	**(2,797)**	**464**	**435**	**(1,639)**	

Source: Cambridge Energy Research Associates.

Table C.4

Change in Average Hourly Interpool Flows : 2004 (Scenario A–Scenario B)
(megawatts)

From	NYCA	PJM	VP	VAC	APS	AEP	FE	ECAR	MECS	WUM	NI	SCI	EMO	OH	TOTAL
NYCA	X	(198)	0	0	0	0	0	0	0	0	0	0	0	(4)	**(202)**
PJM	198	X	(56)	0	(373)	0	(45)	0	0	0	0	0	0	0	**(276)**
VP	0	56	X	(137)	118	(223)	0	0	0	0	0	0	0	0	**(186)**
VAC	0	0	137	X	0	(104)	0	0	0	0	0	0	0	0	**33**
APS	0	373	(118)	0	X	(950)	163	0	0	0	0	0	0	0	**(532)**
AEP	0	0	223	104	950	X	1,026	(852)	1,119	0	(376)	(28)	0	0	**2,166**
FE	0	45	0	0	(163)	(1,026)	X	(21)	760	0	0	0	0	0	**(405)**
ECAR	0	0	0	0	0	852	21	X	43	0	(8)	(3)	0	0	**905**
MECS	0	0	0	0	0	(1,119)	(760)	(43)	X	0	0	0	0	469	**(1,453)**
WUM	0	0	0	0	0	0	0	0	0	X	59	0	0	0	**59**
NI	0	0	0	0	0	376	0	8	0	(59)	X	(154)	0	0	**171**
SCI	0	0	0	0	0	28	0	3	0	0	154	X	(6)	0	**179**
EMO	0	0	0	0	0	0	0	0	0	0	0	6	X	0	**6**
OH	4	0	0	0	0	0	0	0	(469)	0	0	0	0	X	**(465)**
TOTAL	**202**	**276**	**186**	**(33)**	**532**	**(2,166)**	**405**	**(905)**	**1,453**	**(59)**	**(171)**	**(179)**	**(6)**	**465**	

Source: Cambridge Energy Research Associates.

Table C.5

Average Hourly Interpool Flows: 2006 Scenario B
(megawatts)

From	NYCA	PJM	VP	VAC	APS	AEP	FE	ECAR	MECS	WUM	NI	SCI	EMO	OH	TOTAL
NYCA	X	(1,216)	0	0	0	0	0	0	0	0	0	0	0	(1,084)	(2,300)
PJM	1,216	X	264	0	(1,189)	0	(318)	0	0	0	0	0	0	0	(27)
VP	0	(264)	X	(396)	(524)	(570)	0	0	0	0	0	0	0	0	(1,754)
VAC	0	0	396	X	0	(150)	0	0	0	0	0	0	0	0	246
APS	0	1,189	524	0	X	(616)	(303)	0	0	0	0	0	0	0	794
AEP	0	0	570	150	616	X	757	(1,495)	1,790	0	(669)	343	0	0	2,062
FE	0	318	0	0	303	(757)	X	(76)	158	0	0	0	0	0	(54)
ECAR	0	0	0	0	0	1,495	76	X	46	0	(608)	166	0	0	1,175
MECS	0	0	0	0	0	(1,790)	(158)	(46)	X	0	0	0	0	(126)	(2,120)
WUM	0	0	0	0	0	0	0	0	0	X	(660)	0	0	0	(660)
NI	0	0	0	0	0	669	0	608	0	660	X	477	0	0	2,414
SCI	0	0	0	0	0	(343)	0	(166)	0	0	(477)	X	422	0	(564)
EMO	0	0	0	0	0	0	0	0	0	0	0	(422)	X	0	(422)
OH	1,084	0	0	0	0	0	0	0	126	0	0	0	0	X	1,210
TOTAL	2,300	27	1,754	(246)	(794)	(2,062)	54	(1,175)	2,120	660	(2,414)	564	422	(1,210)	

Source: Cambridge Energy Research Associates.

Table C.6

Average Hourly Interpool Flows: 2006 Scenario A
(megawatts)

From	NYCA	PJM	VP	VAC	APS	AEP	FE	ECAR	MECS	WUM	NI	SCI	EMO	OH	TOTAL
NYCA	X	(1,396)	0	0	0	0	0	0	0	0	0	0	0	(1,118)	(2,514)
PJM	1,396	X	243	0	(1,495)	0	(357)	0	0	0	0	0	0	0	(213)
VP	0	(243)	X	(520)	(428)	(746)	0	0	0	0	0	0	0	0	(1,937)
VAC	0	0	520	X	0	(218)	0	0	0	0	0	0	0	0	302
APS	0	1,495	428	0	X	(1,469)	(168)	0	0	0	0	0	0	0	286
AEP	0	0	746	218	1,469	X	1,568	(2,155)	2,633	0	(980)	274	0	0	3,773
FE	0	357	0	0	168	(1,568)	X	(90)	710	0	0	0	0	0	(423)
ECAR	0	0	0	0	0	2,155	90	X	79	0	(638)	154	0	0	1,840
MECS	0	0	0	0	0	(2,633)	(710)	(79)	X	0	0	0	0	183	(3,239)
WUM	0	0	0	0	0	0	0	0	0	X	(577)	0	0	0	(577)
NI	0	0	0	0	0	980	0	638	0	577	X	350	0	0	2,545
SCI	0	0	0	0	0	(274)	0	(154)	0	0	(350)	X	404	0	(374)
EMO	0	0	0	0	0	0	0	0	0	0	0	(404)	X	0	(404)
OH	1,118	0	0	0	0	0	0	0	(183)	0	0	0	0	X	935
TOTAL	2,514	213	1,937	(302)	(286)	(3,773)	423	(1,840)	3,239	577	(2,545)	374	404	(935)	

Source: Cambridge Energy Research Associates.

Table C.7

Change in Average Hourly Inter-pool Flows: 2006 (Scenario A–Scenario B)
(megawatts)

From	NYCA	PJM	VP	VAC	APS	AEP	FE	ECAR	MECS	WUM	NI	SCI	EMO	OH	TOTAL
NYCA	X	(180)	0	0	0	0	0	0	0	0	0	0	0	(34)	(214)
PJM	180	X	(21)	0	(306)	0	(39)	0	0	0	0	0	0	0	(186)
VP	0	21	X	(124)	96	(176)	0	0	0	0	0	0	0	0	(183)
VAC	0	0	124	X	0	(68)	0	0	0	0	0	0	0	0	56
APS	0	306	(96)	0	X	(853)	135	0	0	0	0	0	0	0	(508)
AEP	0	0	176	68	853	X	811	(660)	843	0	(311)	(69)	0	0	1,711
FE	0	39	0	0	(135)	(811)	X	(14)	552	0	0	0	0	0	(369)
ECAR	0	0	0	0	0	660	14	X	33	0	(30)	(12)	0	0	665
MECS	0	0	0	0	0	(843)	(552)	(33)	X	0	0	0	0	309	(1,119)
WUM	0	0	0	0	0	0	0	0	0	X	83	0	0	0	83
NI	0	0	0	0	0	311	0	30	0	(83)	X	(127)	0	0	131
SCI	0	0	0	0	0	69	0	12	0	0	127	X	(18)	0	190
EMO	0	0	0	0	0	0	0	0	0	0	0	18	X	0	18
OH	34	0	0	0	0	0	0	0	(309)	0	0	0	0	X	(275)
TOTAL	214	186	183	(56)	508	(1,711)	369	(665)	1,119	(83)	(131)	(190)	(18)	275	

Source: Cambridge Energy Research Associates.

Table C.8

Average Hourly Interpool Flows: 2008 Scenario B
(megawatts)

From	NYCA	PJM	VP	VAC	APS	AEP	FE	ECAR	MECS	WUM	NI	SCI	EMO	OH	TOTAL
NYCA	X	(925)	0	0	0	0	0	0	0	0	0	0	0	(968)	**(1,893)**
PJM	925	X	275	0	(957)	0	(270)	0	0	0	0	0	0	0	**(27)**
VP	0	(275)	X	(462)	(483)	(737)	0	0	0	0	0	0	0	0	**(1,957)**
VAC	0	0	462	X	0	(445)	0	0	0	0	0	0	0	0	**17**
APS	0	957	483	0	X	(524)	(228)	0	0	0	0	0	0	0	**688**
AEP	0	0	737	445	524	X	801	(1,443)	1,698	0	(703)	270	0	0	**2,329**
FE	0	270	0	0	228	(801)	X	(75)	97	0	0	0	0	0	**(281)**
ECAR	0	0	0	0	0	1,443	75	X	45	0	(517)	152	0	0	**1,198**
MECS	0	0	0	0	0	(1,698)	(97)	(45)	X	0	0	0	0	(162)	**(2,002)**
WUM	0	0	0	0	0	0	0	0	0	X	(677)	0	0	0	**(677)**
NI	0	0	0	0	0	703	0	517	0	677	X	379	0	0	**2,276**
SCI	0	0	0	0	0	(270)	0	(152)	0	0	(379)	X	402	0	**(399)**
EMO	0	0	0	0	0	0	0	0	0	0	0	(402)	X	0	**(402)**
OH	968	0	0	0	0	0	0	0	162	0	0	0	0	X	**1,130**
TOTAL	**1,893**	**27**	**1,957**	**(17)**	**(688)**	**(2,329)**	**281**	**(1,198)**	**2,002**	**677**	**(2,276)**	**399**	**402**	**(1,130)**	

Source: Cambridge Energy Research Associates.

Table C.9

Average Hourly Interpool Flows: 2008 Scenario A
(megawatts)

From	NYCA	PJM	VP	VAC	APS	AEP	FE	ECAR	MECS	WUM	NI	SCI	EMO	OH	TOTAL
NYCA	X	(1,104)	0	0	0	0	0	0	0	0	0	0	0	(993)	**(2,097)**
PJM	1,104	X	242	0	(1,259)	0	(311)	0	0	0	0	0	0	0	**(224)**
VP	0	(242)	X	(600)	(376)	(888)	0	0	0	0	0	0	0	0	**(2,106)**
VAC	0	0	600	X	0	(452)	0	0	0	0	0	0	0	0	**148**
APS	0	1,259	376	0	X	(1,209)	(114)	0	0	0	0	0	0	0	**312**
AEP	0	0	888	452	1,209	X	1,540	(2,040)	2,557	0	(1,035)	169	0	0	**3,740**
FE	0	311	0	0	114	(1,540)	X	(87)	674	0	0	0	0	0	**(528)**
ECAR	0	0	0	0	0	2,040	87	X	76	0	(580)	130	0	0	**1,753**
MECS	0	0	0	0	0	(2,557)	(674)	(76)	X	0	0	0	0	170	**(3,137)**
WUM	0	0	0	0	0	0	0	0	0	X	(583)	0	0	0	**(583)**
NI	0	0	0	0	0	1,035	0	580	0	583	X	239	0	0	**2,437**
SCI	0	0	0	0	0	(169)	0	(130)	0	0	(239)	X	393	0	**(145)**
EMO	0	0	0	0	0	0	0	0	0	0	0	(393)	X	0	**(393)**
OH	993	0	0	0	0	0	0	0	(170)	0	0	0	0	X	**823**
TOTAL	**2,097**	**224**	**2,106**	**(148)**	**(312)**	**(3,740)**	**528**	**(1,753)**	**3,137**	**583**	**(2,437)**	**145**	**393**	**(823)**	

Source: Cambridge Energy Research Associates.

Table C.10

Change in Average Hourly Interpool Flows: 2008 (Scenario A–Scenario B)
(megawatts)

From	**NYCA**	**PJM**	**VP**	**VAC**	**APS**	**AEP**	**FE**	**ECAR**	**MECS**	**WUM**	**NI**	**SCI**	**EMO**	**OH**	**TOTAL**
NYCA	X	(179)	0	0	0	0	0	0	0	0	0	0	0	(25)	**(204)**
PJM	179	X	(33)	0	(302)	0	(41)	0	0	0	0	0	0	0	**(197)**
VP	0	33	X	(138)	107	(151)	0	0	0	0	0	0	0	0	**(149)**
VAC	0	0	138	X	0	(7)	0	0	0	0	0	0	0	0	**131**
APS	0	302	(107)	0	X	(685)	114	0	0	0	0	0	0	0	**(376)**
AEP	0	0	151	7	685	X	739	(597)	859	0	(332)	(101)	0	0	**1,411**
FE	0	41	0	0	(114)	(739)	X	(12)	577	0	0	0	0	0	**(247)**
ECAR	0	0	0	0	0	597	12	X	31	0	(63)	(22)	0	0	**555**
MECS	0	0	0	0	0	(859)	(577)	(31)	X	0	0	0	0	332	**(1,135)**
WUM	0	0	0	0	0	0	0	0	0	X	94	0	0	0	**94**
NI	0	0	0	0	0	332	0	63	0	(94)	X	(140)	0	0	**161**
SCI	0	0	0	0	0	101	0	22	0	0	140	X	(9)	0	**254**
EMO	0	0	0	0	0	0	0	0	0	0	0	9	X	0	**9**
OH	25	0	0	0	0	0	0	0	(332)	0	0	0	0	X	**(307)**
TOTAL	**204**	**197**	**149**	**(131)**	**376**	**(1,411)**	**247**	**(555)**	**1,135**	**(94)**	**(161)**	**(254)**	**(9)**	**307**	

Source: Cambridge Energy Research Associates.

Transmission Constraints

Table C.11

Major Transmission Constraints between the Midwest and the East—2004 Congestion Cost in 2002$ Million

			Percent Time Binding during the Year			Congestion Costs		
Name	From Pool	To Pool	Scenario B	Scenario A	Delta	Scenario B	Scenario A	Delta
FG2353 BLACKO-BEDNGT500-PRNT	APS	APS	75%	78%	4%	$579	$577	($3)
FG50 AP - SOUTH INTERFACE	VACAR	APS	4%	7%	3%	$30	$54	$25
FG2422 NEW HARDINSBG 138-161	ECAR	ECAR	24%	27%	3%	$38	$46	$8
INTERFACE= PJM - CENTRAL	PJM	PJM	3%	9%	6%	$8	$27	$19
FG2406 CLVRDL-LXNGTN500/PRUN	AEP	VACAR	1%	7%	5%	$5	$20	$15
FG2336 BentnHrbr-Palisades34	AEP	MECS	0%	25%	25%	$0	$20	$20
FG1720 Loudoun 500-230 kV Tx	VACAR	VACAR	0%	1%	0%	$12	$17	$5
FG2092 11CLVRPR 138 12G R ST	ECAR	ECAR	43%	41%	-2%	$17	$17	($0)
INTERFACE= PJM - EASTERN	PJM	PJM	2%	4%	2%	$6	$16	$10
FG2358 01WYLIER 345/500TX5-0	APS	APS	4%	15%	10%	$3	$14	$11
FG1708 HALIFAX-PERSON 230/CA	VACAR	VACAR	4%	5%	1%	$8	$12	$5
VEM;HATFL-YUKON;BEDNG-DOUB	APS	APS	4%	7%	2%	$6	$11	$5
FG2488 11BLUE L 161 20BLIT C	ECAR	ECAR	5%	7%	1%	$10	$11	$1
FG1213 Bluffton-Rosehl 115 +	VACAR	VACAR	9%	8%	-1%	$11	$10	($1)

Source: Cambridge Energy Research Associates.

Table C.12

Major Transmission Constraints between the Midwest and the East—2006 Congestion Cost in 2002$ Million

			Percent Time Binding during the Year			Congestion Costs		
Name	From Pool	To Pool	Scenario B	Scenario A	Delta	Scenario B	Scenario A	Delta
FG2353 BLACKO-BEDNGT500-PRNT	APS	APS	79%	80%	0%	$628	$624	($5)
FG1720 Loudoun 500-230 kV Tx	VACAR	VACAR	1%	1%	0%	$56	$59	$3
FG2422 NEW HARDINSBG 138-161	ECAR	ECAR	30%	33%	3%	$43	$47	$4
FG50 AP - SOUTH INTERFACE	VACAR	APS	2%	5%	3%	$14	$36	$23
FG2092 11CLVRPR 138 12G R ST	ECAR	ECAR	49%	47%	-2%	$24	$25	$1
VEM;HATFL-YUKON;BEDNG-DOUB	APS	APS	7%	9%	2%	$10	$18	$9
FG2336 BentnHrbr-Palisades34	AEP	MECS	0%	21%	21%	$1	$18	$17
FG2203 BUFFINGTON_345_138_PI	ECAR	ECAR	1%	1%	0%	$15	$15	$1
FG20 Erie West-Erie South	PJM	PJM	5%	8%	3%	$7	$14	$7
FG2083 10CULLEY 138 10GRNDVW	ECAR	ECAR	28%	31%	3%	$11	$14	$2
FG2406 CLVRDL-LXNGTN500/PRUN	AEP	VACAR	1%	5%	4%	$4	$13	$10
FG1710 CHSTF B-TYLER 230/CAR	VACAR	VACAR	4%	3%	-1%	$14	$11	($3)

Source: Cambridge Energy Research Associates.

Table C.13

Major Transmission Constraints Between the Midwest and the East—2008 Congestion Cost in 2002$ Million

			Percent Time Binding during the Year			Congestion Costs		
Name	From Pool	To Pool	Scenario B	Scenario A	Delta	Scenario B	Scenario A	Delta
FG2353 BLACKO-BEDNGT500-PRNT	APS	APS	75%	75%	0%	$657	$656	($1)
FG1720 Loudoun 500-230 kV Tx	VACAR	VACAR	2%	2%	0%	$133	$135	$2
FG2422 NEW HARDINSBG 138-161	ECAR	ECAR	24%	25%	1%	$47	$48	$1
FG1721 Loudoun 500-230 kV Tx	VACAR	VACAR	1%	1%	0%	$44	$45	$1
FG50 AP - SOUTH INTERFACE	VACAR	APS	2%	4%	2%	$16	$34	$18
FG2203 BUFFINGTON_345_138_PI	ECAR	ECAR	2%	2%	0%	$29	$29	$0
FG2092 11CLVRPR 138 12G R ST	ECAR	ECAR	47%	47%	1%	$27	$29	$2
FG1710 CHSTF B-TYLER 230/CAR	VACAR	VACAR	5%	5%	0%	$32	$29	($3)
FG2406 CLVRDL-LXNGTN500/PRUN	AEP	VACAR	3%	10%	7%	$6	$28	$22
FG1712 DICKERSN-PL VIEW 230/	PJM	VACAR	3%	3%	0%	$19	$18	($1)
FG2083 10CULLEY 138 10GRNDVW	ECAR	ECAR	32%	34%	2%	$14	$16	$2
FG2336 BentnHrbr-Palisades34	AEP	MECS	1%	19%	18%	$1	$16	$15

Source: Cambridge Energy Research Associates

AEP Plant Result

Table C.14

All-hour Average Price

(2002$/MWh)

MAPS Unit Name	Unit Name	Plant Operator	2004 A	2004 B	2006 A	2006 B	2008 A	2008 B
AMOS 01	Amos 1	Appalachian Power Co.	20.0	18.8	21.1	19.9	22.7	21.4
AMOS 02	Amos 2	Appalachian Power Co.	20.2	19.0	21.4	20.1	22.9	21.6
AMOS 03	Amos 3	Appalachian Power Co.	20.0	18.8	21.1	19.9	22.7	21.4
CLINCH01	Clinch 1	Appalachian Power Co.	21.5	20.1	22.9	21.5	23.9	22.5
CLINCH02	Clinch 2	Appalachian Power Co.	21.5	20.1	22.9	21.5	23.9	22.5
CLINCH03	Clinch 3	Appalachian Power Co.	21.5	20.1	22.9	21.5	23.9	22.5
GLEN L05	Glen Lyn 5	Appalachian Power Co.	22.0	20.8	23.4	22.1	24.4	23.1
GLEN L06	Glen Lyn 6	Appalachian Power Co.	22.0	20.8	23.4	22.1	24.4	23.1
KANAWH01	Kanawha 1	Appalachian Power Co.	20.7	19.5	21.9	20.6	23.3	22.0
KANAWH02	Kanawha 2	Appalachian Power Co.	20.7	19.5	21.9	20.6	23.3	22.0
MOUNTR01	Mountaineer 1	Appalachian Power Co.	19.7	18.6	20.9	19.6	22.4	21.1
SPORN 01	Sporn 1	Appalachian Power Co.	19.9	18.8	21.1	19.9	22.6	21.3
SPORN 02	Sporn 2	Appalachian Power Co.	19.9	18.8	21.1	19.9	22.6	21.3
SPORN 03	Sporn 3	Appalachian Power Co.	19.9	18.8	21.1	19.9	22.6	21.3
SPORN 04	Sporn 4	Appalachian Power Co.	19.9	18.8	21.1	19.9	22.6	21.3
SPORN 05	Sporn 5	Appalachian Power Co.	20.0	18.9	21.1	19.9	22.6	21.3
BECKJF6A	Beckjord 6	Columbus Southern Power Co.	19.6	18.4	20.6	19.2	22.0	20.5
CONESV01	Conesville 1	Columbus Southern Power Co.	19.5	18.4	20.7	19.5	22.3	20.9
CONESV02	Conesville 2	Columbus Southern Power Co.	19.5	18.4	20.6	19.4	22.2	20.8
CONESV03	Conesville 3	Columbus Southern Power Co.	19.5	18.4	20.6	19.4	22.2	20.8
CONESV4A	Conesville 4	Columbus Southern Power Co.	19.6	18.5	20.8	19.6	22.4	21.0
CONESV05	Conesville 5	Columbus Southern Power Co.	19.6	18.5	20.8	19.6	22.4	21.0
CONESV06	Conesville 6	Columbus Southern Power Co.	19.6	18.5	20.8	19.6	22.4	21.0
PICWAY05	Picway 5	Columbus Southern Power Co.	19.6	18.6	20.8	19.6	22.4	21.1
STUART1A	Stuart 1	Columbus Southern Power Co.	19.8	18.8	21.0	19.9	22.7	21.4
STUART2A	Stuart 2	Columbus Southern Power Co.	19.8	18.8	21.0	19.9	22.7	21.4
STUART3A	Stuart 3	Columbus Southern Power Co.	19.8	18.8	21.0	19.9	22.7	21.4
STUART4A	Stuart 4	Columbus Southern Power Co.	19.8	18.8	21.0	19.9	22.7	21.4
ZIMMER1A	Zimmer 1	Columbus Southern Power Co.	19.8	18.7	21.1	19.7	22.9	21.4
D C CO01	Cook 1	Indiana Michigan Power Co.	19.4	18.4	20.7	19.5	22.3	21.0
D C CO02	Cook 2	Indiana Michigan Power Co.	19.5	18.5	20.7	19.5	22.3	21.0
ROCKPO01	Rockport 1	Indiana Michigan Power Co.	19.5	18.6	20.6	19.6	22.3	21.1
ROCKPO02	Rockport 2	Indiana Michigan Power Co.	19.5	18.6	20.6	19.6	22.3	21.1
TANNER01	Tanners 1	Indiana Michigan Power Co.	19.6	18.7	20.8	19.6	22.4	21.1
TANNER02	Tanners 2	Indiana Michigan Power Co.	19.6	18.7	20.8	19.6	22.4	21.1
TANNER03	Tanners 3	Indiana Michigan Power Co.	19.6	18.7	20.8	19.6	22.4	21.1
TANNER04	Tanners 4	Indiana Michigan Power Co.	19.6	18.7	20.8	19.6	22.4	21.1
BIG SA01	Big Sandy 1	Kentucky Power Co	20.2	19.1	21.4	20.2	22.9	21.6
BIG SA02	Big Sandy 2	Kentucky Power Co	20.2	19.1	21.4	20.2	22.9	21.6
CARDIN01	Cardinal 1	Ohio Power Co.	18.9	17.7	20.1	18.8	21.7	20.2
GAVIN 01	Gavin 1	Ohio Power Co.	19.8	18.6	20.9	19.6	22.5	21.2
GAVIN 02	Gavin 2	Ohio Power Co.	19.8	18.6	20.9	19.6	22.5	21.2
KAMMER01	Kammer 1	Ohio Power Co.	19.0	17.8	20.1	18.8	21.7	20.2
KAMMER02	Kammer 2	Ohio Power Co.	19.0	17.8	20.1	18.8	21.7	20.2
KAMMER03	Kammer 3	Ohio Power Co.	19.0	17.8	20.1	18.8	21.7	20.2
MITCHE01	Mitchell 1	Ohio Power Co.	18.9	17.7	20.0	18.6	21.5	20.0
MITCHE02	Mitchell 2	Ohio Power Co.	19.0	17.8	20.1	18.8	21.7	20.2
MUSKIN01	Muskingum 1	Ohio Power Co.	19.3	18.1	20.4	19.1	22.0	20.5
MUSKIN02	Muskingum 2	Ohio Power Co.	19.5	18.4	20.7	19.4	22.2	20.8
MUSKIN03	Muskingum 3	Ohio Power Co.	19.3	18.1	20.4	19.1	22.0	20.5
MUSKIN04	Muskingum 4	Ohio Power Co.	19.5	18.4	20.7	19.4	22.2	20.8
MUSKIN05	Muskingum 5	Ohio Power Co.	19.5	18.4	20.7	19.4	22.2	20.8
CLIFTY01	Clifty Creek 1	Ohio Valley Electric Corp	19.6	18.7	20.7	19.6	22.2	21.0
CLIFTY02	Clifty Creek 2	Ohio Valley Electric Corp	19.6	18.7	20.7	19.6	22.2	21.0
CLIFTY03	Clifty Creek 3	Ohio Valley Electric Corp	19.6	18.7	20.7	19.6	22.2	21.0
CLIFTY04	Clifty Creek 4	Ohio Valley Electric Corp	19.6	18.7	20.7	19.6	22.2	21.0
CLIFTY05	Clifty Creek 5	Ohio Valley Electric Corp	19.6	18.7	20.7	19.6	22.2	21.0
CLIFTY06	Clifty Creek 6	Ohio Valley Electric Corp	19.6	18.7	20.7	19.6	22.2	21.0
KYGER 01	Kyger Creek 1	Ohio Valley Electric Corp	19.9	18.8	21.0	19.9	22.5	21.3
KYGER 02	Kyger Creek 2	Ohio Valley Electric Corp	19.9	18.8	21.0	19.9	22.5	21.3
KYGER 03	Kyger Creek 3	Ohio Valley Electric Corp	19.9	18.8	21.0	19.9	22.5	21.3
KYGER 04	Kyger Creek 4	Ohio Valley Electric Corp	19.9	18.8	21.0	19.9	22.5	21.3
KYGER 05	Kyger Creek 5	Ohio Valley Electric Corp	19.9	18.8	21.0	19.9	22.5	21.3

Source: Cambridge Energy Research Associates.

Table C.15

On-peak Average Price
(2002$/MWh)

MAPS Unit Name	Unit Name	Plant Operator	2004 A	2004 B	2006 A	2006 B	2008 A	2008 B
AMOS 01	Amos 1	Appalachian Power Co.	24.2	22.7	25.9	24.0	28.8	26.7
AMOS 02	Amos 2	Appalachian Power Co.	24.5	23.0	26.2	24.3	29.0	26.9
AMOS 03	Amos 3	Appalachian Power Co.	24.2	22.7	25.9	24.0	28.8	26.7
CLINCH01	Clinch 1	Appalachian Power Co.	26.2	24.5	27.9	26.1	30.0	28.1
CLINCH02	Clinch 2	Appalachian Power Co.	26.2	24.5	27.9	26.1	30.0	28.1
CLINCH03	Clinch 3	Appalachian Power Co.	26.2	24.5	27.9	26.1	30.0	28.1
GLEN L05	Glen Lyn 5	Appalachian Power Co.	27.0	25.4	28.7	26.9	30.8	28.8
GLEN L06	Glen Lyn 6	Appalachian Power Co.	27.0	25.4	28.7	26.9	30.8	28.8
KANAWH01	Kanawha 1	Appalachian Power Co.	25.2	23.6	26.8	25.0	29.5	27.4
KANAWH02	Kanawha 2	Appalachian Power Co.	25.2	23.6	26.8	25.0	29.5	27.4
MOUNTR01	Mountaineer 1	Appalachian Power Co.	23.8	22.3	25.5	23.6	28.4	26.2
SPORN 01	Sporn 1	Appalachian Power Co.	24.1	22.6	25.8	24.0	28.6	26.5
SPORN 02	Sporn 2	Appalachian Power Co.	24.1	22.6	25.8	24.0	28.6	26.5
SPORN 03	Sporn 3	Appalachian Power Co.	24.1	22.6	25.8	24.0	28.6	26.5
SPORN 04	Sporn 4	Appalachian Power Co.	24.1	22.6	25.8	24.0	28.6	26.5
SPORN 05	Sporn 5	Appalachian Power Co.	24.2	22.7	25.9	24.1	28.6	26.5
BECKJF6A	Beckjord 6	Columbus Southern Power Co.	23.7	22.2	25.2	23.4	27.8	25.6
CONESV01	Conesville 1	Columbus Southern Power Co.	23.6	22.1	25.4	23.5	28.2	26.0
CONESV02	Conesville 2	Columbus Southern Power Co.	23.5	22.0	25.3	23.3	28.1	25.9
CONESV03	Conesville 3	Columbus Southern Power Co.	23.5	22.0	25.3	23.3	28.1	25.9
CONESV4A	Conesville 4	Columbus Southern Power Co.	23.7	22.2	25.5	23.6	28.4	26.2
CONESV05	Conesville 5	Columbus Southern Power Co.	23.7	22.2	25.5	23.6	28.4	26.2
CONESV06	Conesville 6	Columbus Southern Power Co.	23.7	22.2	25.5	23.6	28.4	26.2
PICWAY05	Picway 5	Columbus Southern Power Co.	23.8	22.3	25.5	23.7	28.5	26.3
STUART1A	Stuart 1	Columbus Southern Power Co.	24.1	22.7	25.9	24.2	29.0	27.0
STUART2A	Stuart 2	Columbus Southern Power Co.	24.1	22.7	25.9	24.2	29.0	27.0
STUART3A	Stuart 3	Columbus Southern Power Co.	24.1	22.7	25.9	24.2	29.0	27.0
STUART4A	Stuart 4	Columbus Southern Power Co.	24.1	22.7	25.9	24.2	29.0	27.0
ZIMMER1A	Zimmer 1	Columbus Southern Power Co.	24.2	22.8	26.1	24.3	29.4	27.4
D C CO01	Cook 1	Indiana Michigan Power Co.	23.9	22.4	25.8	23.9	28.7	26.5
D C CO02	Cook 2	Indiana Michigan Power Co.	23.9	22.4	25.8	23.9	28.7	26.5
ROCKPO01	Rockport 1	Indiana Michigan Power Co.	23.8	22.4	25.5	23.8	28.5	26.4
ROCKPO02	Rockport 2	Indiana Michigan Power Co.	23.8	22.4	25.5	23.8	28.5	26.4
TANNER01	Tanners 1	Indiana Michigan Power Co.	23.9	22.5	25.7	23.8	28.7	26.5
TANNER02	Tanners 2	Indiana Michigan Power Co.	23.9	22.5	25.7	23.8	28.7	26.5
TANNER03	Tanners 3	Indiana Michigan Power Co.	23.9	22.5	25.6	23.8	28.6	26.4
TANNER04	Tanners 4	Indiana Michigan Power Co.	23.9	22.5	25.6	23.8	28.6	26.4
BIG SA01	Big Sandy 1	Kentucky Power Co	24.6	23.0	26.3	24.5	29.0	27.0
BIG SA02	Big Sandy 2	Kentucky Power Co	24.5	23.0	26.2	24.4	28.9	26.9
CARDIN01	Cardinal 1	Ohio Power Co.	22.5	21.1	24.5	22.5	27.2	24.9
GAVIN 01	Gavin 1	Ohio Power Co.	23.9	22.3	25.5	23.7	28.4	26.3
GAVIN 02	Gavin 2	Ohio Power Co.	23.9	22.3	25.5	23.7	28.4	26.3
KAMMER01	Kammer 1	Ohio Power Co.	22.7	21.1	24.5	22.5	27.3	25.0
KAMMER02	Kammer 2	Ohio Power Co.	22.7	21.1	24.5	22.5	27.3	25.0
KAMMER03	Kammer 3	Ohio Power Co.	22.7	21.1	24.5	22.5	27.3	25.0
MITCHE01	Mitchell 1	Ohio Power Co.	22.6	21.0	24.2	22.3	27.0	24.8
MITCHE02	Mitchell 2	Ohio Power Co.	22.7	21.2	24.5	22.5	27.3	25.0
MUSKIN01	Muskingum 1	Ohio Power Co.	23.2	21.6	24.9	23.0	27.7	25.5
MUSKIN02	Muskingum 2	Ohio Power Co.	23.5	22.0	25.2	23.3	28.1	25.9
MUSKIN03	Muskingum 3	Ohio Power Co.	23.2	21.6	24.9	23.0	27.7	25.5
MUSKIN04	Muskingum 4	Ohio Power Co.	23.5	22.0	25.2	23.3	28.1	25.9
MUSKIN05	Muskingum 5	Ohio Power Co.	23.5	22.0	25.2	23.3	28.1	25.9
CLIFTY01	Clifty Creek 1	Ohio Valley Electric Corp	23.8	22.4	25.4	23.7	28.3	26.2
CLIFTY02	Clifty Creek 2	Ohio Valley Electric Corp	23.8	22.4	25.4	23.7	28.3	26.2
CLIFTY03	Clifty Creek 3	Ohio Valley Electric Corp	23.8	22.4	25.4	23.7	28.3	26.2
CLIFTY04	Clifty Creek 4	Ohio Valley Electric Corp	23.8	22.4	25.4	23.7	28.3	26.2
CLIFTY05	Clifty Creek 5	Ohio Valley Electric Corp	23.8	22.4	25.4	23.7	28.3	26.2
CLIFTY06	Clifty Creek 6	Ohio Valley Electric Corp	23.8	22.4	25.4	23.7	28.3	26.2
KYGER 01	Kyger Creek 1	Ohio Valley Electric Corp	24.1	22.6	25.8	24.0	28.5	26.5
KYGER 02	Kyger Creek 2	Ohio Valley Electric Corp	24.1	22.6	25.8	24.0	28.5	26.5
KYGER 03	Kyger Creek 3	Ohio Valley Electric Corp	24.1	22.6	25.8	24.0	28.5	26.5
KYGER 04	Kyger Creek 4	Ohio Valley Electric Corp	24.1	22.6	25.8	24.0	28.5	26.5
KYGER 05	Kyger Creek 5	Ohio Valley Electric Corp	24.1	22.6	25.8	24.0	28.5	26.5

Source: Cambridge Energy Research Associates.

Table C.16

Off-peak Average Price

(2002$/MWh)

MAPS Unit Name	Unit Name	Plant Operator	2004 A	2004 B	2006 A	2006 B	2008 A	2008 B
AMOS 01	Amos 1	Appalachian Power Co.	16.1	15.3	16.9	16.2	17.2	16.6
AMOS 02	Amos 2	Appalachian Power Co.	16.2	15.5	17.0	16.3	17.3	16.7
AMOS 03	Amos 3	Appalachian Power Co.	16.1	15.3	16.9	16.2	17.2	16.6
CLINCH01	Clinch 1	Appalachian Power Co.	17.2	16.1	18.4	17.3	18.3	17.4
CLINCH02	Clinch 2	Appalachian Power Co.	17.2	16.1	18.4	17.3	18.3	17.4
CLINCH03	Clinch 3	Appalachian Power Co.	17.2	16.1	18.4	17.3	18.3	17.4
GLEN L05	Glen Lyn 5	Appalachian Power Co.	17.5	16.6	18.6	17.7	18.5	17.8
GLEN L06	Glen Lyn 6	Appalachian Power Co.	17.5	16.6	18.6	17.7	18.5	17.8
KANAWH01	Kanawha 1	Appalachian Power Co.	16.6	15.8	17.4	16.7	17.7	17.0
KANAWH02	Kanawha 2	Appalachian Power Co.	16.6	15.8	17.4	16.7	17.7	17.0
MOUNTR01	Mountaineer 1	Appalachian Power Co.	16.0	15.2	16.7	16.0	17.0	16.4
SPORN 01	Sporn 1	Appalachian Power Co.	16.1	15.3	16.8	16.1	17.1	16.5
SPORN 02	Sporn 2	Appalachian Power Co.	16.1	15.3	16.8	16.1	17.1	16.5
SPORN 03	Sporn 3	Appalachian Power Co.	16.1	15.3	16.8	16.1	17.1	16.5
SPORN 04	Sporn 4	Appalachian Power Co.	16.1	15.3	16.8	16.1	17.1	16.5
SPORN 05	Sporn 5	Appalachian Power Co.	16.1	15.4	16.8	16.2	17.1	16.6
BECKJF6A	Beckjord 6	Columbus Southern Power Co.	15.9	15.0	16.5	15.5	16.8	15.9
CONESV01	Conesville 1	Columbus Southern Power Co.	15.8	15.1	16.5	15.8	16.8	16.2
CONESV02	Conesville 2	Columbus Southern Power Co.	15.8	15.1	16.5	15.8	16.8	16.2
CONESV03	Conesville 3	Columbus Southern Power Co.	15.8	15.1	16.5	15.8	16.8	16.2
CONESV4A	Conesville 4	Columbus Southern Power Co.	15.8	15.2	16.5	15.9	16.8	16.3
CONESV05	Conesville 5	Columbus Southern Power Co.	15.8	15.2	16.5	15.9	16.8	16.3
CONESV06	Conesville 6	Columbus Southern Power Co.	15.8	15.2	16.5	15.9	16.8	16.3
PICWAY05	Picway 5	Columbus Southern Power Co.	15.9	15.2	16.5	15.9	16.9	16.3
STUART1A	Stuart 1	Columbus Southern Power Co.	15.9	15.3	16.5	16.0	16.9	16.4
STUART2A	Stuart 2	Columbus Southern Power Co.	15.9	15.3	16.5	16.0	16.9	16.4
STUART3A	Stuart 3	Columbus Southern Power Co.	15.9	15.3	16.5	16.0	16.9	16.4
STUART4A	Stuart 4	Columbus Southern Power Co.	15.9	15.3	16.5	16.0	16.9	16.4
ZIMMER1A	Zimmer 1	Columbus Southern Power Co.	15.9	15.0	16.5	15.5	16.9	16.0
D C CO01	Cook 1	Indiana Michigan Power Co.	15.4	14.8	16.0	15.5	16.4	15.9
D C CO02	Cook 2	Indiana Michigan Power Co.	15.5	14.9	16.1	15.6	16.5	15.9
ROCKPO01	Rockport 1	Indiana Michigan Power Co.	15.6	15.1	16.2	15.8	16.6	16.2
ROCKPO02	Rockport 2	Indiana Michigan Power Co.	15.6	15.1	16.2	15.8	16.6	16.2
TANNER01	Tanners 1	Indiana Michigan Power Co.	15.7	15.2	16.3	15.9	16.7	16.2
TANNER02	Tanners 2	Indiana Michigan Power Co.	15.7	15.2	16.3	15.9	16.7	16.2
TANNER03	Tanners 3	Indiana Michigan Power Co.	15.8	15.2	16.4	15.9	16.7	16.3
TANNER04	Tanners 4	Indiana Michigan Power Co.	15.8	15.2	16.4	15.9	16.7	16.3
BIG SA01	Big Sandy 1	Kentucky Power Co	16.3	15.5	17.1	16.4	17.4	16.8
BIG SA02	Big Sandy 2	Kentucky Power Co	16.3	15.5	17.0	16.3	17.3	16.7
CARDIN01	Cardinal 1	Ohio Power Co.	15.5	14.6	16.2	15.4	16.5	15.8
GAVIN 01	Gavin 1	Ohio Power Co.	16.0	15.2	16.7	16.0	17.1	16.4
GAVIN 02	Gavin 2	Ohio Power Co.	16.0	15.2	16.7	16.0	17.1	16.4
KAMMER01	Kammer 1	Ohio Power Co.	15.6	14.7	16.2	15.5	16.5	15.8
KAMMER02	Kammer 2	Ohio Power Co.	15.6	14.7	16.2	15.5	16.5	15.8
KAMMER03	Kammer 3	Ohio Power Co.	15.6	14.7	16.2	15.5	16.5	15.8
MITCHE01	Mitchell 1	Ohio Power Co.	15.6	14.6	16.1	15.4	16.5	15.7
MITCHE02	Mitchell 2	Ohio Power Co.	15.6	14.7	16.2	15.5	16.5	15.8
MUSKIN01	Muskingum 1	Ohio Power Co.	15.8	14.9	16.4	15.7	16.7	16.1
MUSKIN02	Muskingum 2	Ohio Power Co.	15.8	15.1	16.5	15.8	16.8	16.2
MUSKIN03	Muskingum 3	Ohio Power Co.	15.8	14.9	16.4	15.7	16.7	16.1
MUSKIN04	Muskingum 4	Ohio Power Co.	15.8	15.1	16.5	15.8	16.8	16.2
MUSKIN05	Muskingum 5	Ohio Power Co.	15.8	15.1	16.5	15.8	16.8	16.2
CLIFTY01	Clifty Creek 1	Ohio Valley Electric Corp	15.8	15.2	16.4	15.9	16.7	16.3
CLIFTY02	Clifty Creek 2	Ohio Valley Electric Corp	15.8	15.2	16.4	15.9	16.7	16.3
CLIFTY03	Clifty Creek 3	Ohio Valley Electric Corp	15.8	15.2	16.4	15.9	16.7	16.3
CLIFTY04	Clifty Creek 4	Ohio Valley Electric Corp	15.8	15.2	16.4	15.9	16.7	16.3
CLIFTY05	Clifty Creek 5	Ohio Valley Electric Corp	15.8	15.2	16.4	15.9	16.7	16.3
CLIFTY06	Clifty Creek 6	Ohio Valley Electric Corp	15.8	15.2	16.4	15.9	16.7	16.3
KYGER 01	Kyger Creek 1	Ohio Valley Electric Corp	16.1	15.3	16.7	16.1	17.1	16.5
KYGER 02	Kyger Creek 2	Ohio Valley Electric Corp	16.1	15.3	16.7	16.1	17.1	16.5
KYGER 03	Kyger Creek 3	Ohio Valley Electric Corp	16.1	15.3	16.7	16.1	17.1	16.5
KYGER 04	Kyger Creek 4	Ohio Valley Electric Corp	16.1	15.3	16.7	16.1	17.1	16.5
KYGER 05	Kyger Creek 5	Ohio Valley Electric Corp	16.1	15.3	16.7	16.1	17.1	16.5

Source: Cambridge Energy Research Associates.

Table C.17

Annual Unit Generation

(GWh)

MAPS Unit Name	Unit Name	Plant Operator	Capacity (MW)	2004 A	2004 B	2006 A	2006 B	2008 A	2008 B
AMOS 01	Amos 1	Appalachian Power Co.	800	5,080	6,000	6,005	6,014	5,813	5,799
AMOS 02	Amos 2	Appalachian Power Co.	800	6,014	5,978	6,005	6,013	5,808	5,815
AMOS 03	Amos 3	Appalachian Power Co.	1,300	9,701	9,467	9,724	9,708	9,139	8,976
CLINCH01	Clinch 1	Appalachian Power Co.	230	1,559	1,284	1,575	1,462	1,602	1,504
CLINCH02	Clinch 2	Appalachian Power Co.	230	1,442	1,196	1,542	1,317	1,538	1,400
CLINCH03	Clinch 3	Appalachian Power Co.	230	1,595	1,331	1,569	1,464	1,582	1,485
GLEN L05	Glen Lyn 5	Appalachian Power Co.	90	337	181	245	168	330	216
GLEN L06	Glen Lyn 6	Appalachian Power Co.	235	1,382	1,147	1,142	889	1,228	994
KANAWH01	Kanawha 1	Appalachian Power Co.	195	1,231	1,026	1,310	1,223	1,337	1,250
KANAWH02	Kanawha 2	Appalachian Power Co.	195	1,166	978	1,244	1,101	1,289	1,231
MOUNTR01	Mountaineer 1	Appalachian Power Co.	1,300	9,367	8,630	9,464	9,120	8,160	7,069
SPORN 01	Sporn 1	Appalachian Power Co.	145	841	642	835	630	914	803
SPORN 02	Sporn 2	Appalachian Power Co.	145	805	581	779	595	871	750
SPORN 03	Sporn 3	Appalachian Power Co.	145	850	602	810	612	815	667
SPORN 04	Sporn 4	Appalachian Power Co.	145	814	592	760	597	876	767
SPORN 05	Sporn 5	Appalachian Power Co.	440	2,798	2,313	2,748	2,484	2,702	2,540
BECKJF6A	Beckjord 6	Columbus Southern Power Co.	52	374	335	388	380	361	312
CONESV01	Conesville 1	Columbus Southern Power Co.	115	226	60	232	112	428	295
CONESV02	Conesville 2	Columbus Southern Power Co.	115	267	82	294	163	477	328
CONESV03	Conesville 3	Columbus Southern Power Co.	165	408	128	422	216	678	533
CONESV4A	Conesville 4	Columbus Southern Power Co.	339	1,514	868	1,408	1,038	2,012	1,737
CONESV05	Conesville 5	Columbus Southern Power Co.	400	2,435	2,058	2,532	2,240	2,596	2,466
CONESV06	Conesville 6	Columbus Southern Power Co.	400	2,474	2,036	2,363	2,084	2,467	2,371
PICWAY05	Picway 5	Columbus Southern Power Co.	90	244	76	226	101	348	255
STUART1A	Stuart 1	Columbus Southern Power Co.	152	972	803	1,024	902	1,056	994
STUART2A	Stuart 2	Columbus Southern Power Co.	152	1,034	919	1,069	1,034	1,093	1,078
STUART3A	Stuart 3	Columbus Southern Power Co.	152	975	789	1,034	955	1,064	1,031
STUART4A	Stuart 4	Columbus Southern Power Co.	152	994	837	1,048	991	1,080	1,058
ZIMMER1A	Zimmer 1	Columbus Southern Power Co.	330	2,434	2,341	2,291	2,126	2,347	2,225
D C CO01	Cook 1	Indiana Michigan Power Co.	1,000	8,096	8,096	8,079	8,079	8,103	8,103
D C CO02	Cook 2	Indiana Michigan Power Co.	1,115	9,077	9,077	9,035	9,035	9,062	9,062
ROCKPO01	Rockport 1	Indiana Michigan Power Co.	1,300	9,239	8,560	9,162	9,032	9,310	9,252
ROCKPO02	Rockport 2	Indiana Michigan Power Co.	1,300	9,356	8,476	9,208	9,011	9,437	9,304
TANNER01	Tanners 1	Indiana Michigan Power Co.	140	603	325	650	508	605	530
TANNER02	Tanners 2	Indiana Michigan Power Co.	140	671	450	669	520	636	558
TANNER03	Tanners 3	Indiana Michigan Power Co.	200	972	666	1,008	795	903	793
TANNER04	Tanners 4	Indiana Michigan Power Co.	500	3,619	3,344	3,533	3,445	3,644	3,602
BIG SA01	Big Sandy 1	Kentucky Power Co	260	1,681	1,430	1,703	1,555	1,741	1,662
BIG SA02	Big Sandy 2	Kentucky Power Co	800	5,951	5,783	5,916	5,855	5,947	5,963
CARDIN01	Cardinal 1	Ohio Power Co.	585	4,454	4,142	3,966	3,471	4,100	3,716
GAVIN 01	Gavin 1	Ohio Power Co.	1,300	9,811	9,811	9,781	9,781	9,806	9,811
GAVIN 02	Gavin 2	Ohio Power Co.	1,300	9,811	9,811	9,781	9,781	9,808	9,811
KAMMER01	Kammer 1	Ohio Power Co.	200	1,378	1,100	1,472	1,420	1,324	1,172
KAMMER02	Kammer 2	Ohio Power Co.	200	1,370	1,063	1,504	1,467	1,261	1,101
KAMMER03	Kammer 3	Ohio Power Co.	200	1,373	1,068	1,473	1,417	1,264	1,142
MITCHE01	Mitchell 1	Ohio Power Co.	800	3,074	3,186	3,847	2,545	4,047	3,106
MITCHE02	Mitchell 2	Ohio Power Co.	800	3,156	3,632	3,839	3,069	4,403	3,642
MUSKIN01	Muskingum 1	Ohio Power Co.	190	899	404	711	496	994	779
MUSKIN02	Muskingum 2	Ohio Power Co.	190	948	486	777	551	1,024	825
MUSKIN03	Muskingum 3	Ohio Power Co.	205	897	447	736	508	1,121	899
MUSKIN04	Muskingum 4	Ohio Power Co.	205	1,091	632	1,007	707	1,195	1,020
MUSKIN05	Muskingum 5	Ohio Power Co.	575	3,478	4,078	4,277	4,136	4,334	4,325
CLIFTY01	Clifty Creek 1	Ohio Valley Electric Corp	88	621	595	627	614	640	617
CLIFTY02	Clifty Creek 2	Ohio Valley Electric Corp	87	627	605	632	621	642	633
CLIFTY03	Clifty Creek 3	Ohio Valley Electric Corp	88	624	592	630	618	641	617
CLIFTY04	Clifty Creek 4	Ohio Valley Electric Corp	83	593	567	597	585	608	597
CLIFTY05	Clifty Creek 5	Ohio Valley Electric Corp	89	621	580	629	615	642	631
CLIFTY06	Clifty Creek 6	Ohio Valley Electric Corp	82	572	528	578	558	591	580
KYGER 01	Kyger Creek 1	Ohio Valley Electric Corp	89	579	483	602	550	615	599
KYGER 02	Kyger Creek 2	Ohio Valley Electric Corp	83	537	409	560	487	573	545
KYGER 03	Kyger Creek 3	Ohio Valley Electric Corp	86	554	416	582	495	597	559
KYGER 04	Kyger Creek 4	Ohio Valley Electric Corp	84	519	391	555	470	574	527
KYGER 05	Kyger Creek 5	Ohio Valley Electric Corp	84	537	401	562	483	582	537
	Total	American Electric Power	23,686	156,726	144,913	158,778	149,021	160,784	152,570

Source: Cambridge Energy Research Associates

Table C.18

Annual Unit Capacity Factor
(percent)

MAPS Unit Name	Unit Name	Plant Operator	Capacity (MW)	2004 A	2004 B	2006 A	2006 B	2008 A	2008 B
AMOS 01	Amos 1	Appalachian Power Co.	800	72.3%	85.4%	85.7%	85.8%	82.7%	82.5%
AMOS 02	Amos 2	Appalachian Power Co.	800	85.6%	85.1%	85.7%	85.8%	82.6%	82.7%
AMOS 03	Amos 3	Appalachian Power Co.	1,300	85.0%	82.9%	85.4%	85.2%	80.0%	78.6%
CLINCH01	Clinch 1	Appalachian Power Co.	230	76.2%	62.8%	77.2%	71.7%	78.3%	73.5%
CLINCH02	Clinch 2	Appalachian Power Co.	230	70.5%	58.5%	75.6%	64.5%	75.2%	68.5%
CLINCH03	Clinch 3	Appalachian Power Co.	230	78.0%	65.0%	76.9%	71.7%	77.3%	72.6%
GLEN L05	Glen Lyn 5	Appalachian Power Co.	90	41.3%	22.2%	30.1%	20.6%	40.5%	26.5%
GLEN L06	Glen Lyn 6	Appalachian Power Co.	235	66.1%	54.9%	54.8%	42.6%	58.7%	47.6%
KANAWH01	Kanawha 1	Appalachian Power Co.	195	70.8%	59.0%	75.6%	70.5%	76.9%	71.9%
KANAWH02	Kanawha 2	Appalachian Power Co.	195	67.1%	56.3%	71.8%	63.5%	74.1%	70.8%
MOUNTR01	Mountaineer 1	Appalachian Power Co.	1,300	82.0%	75.6%	83.1%	80.1%	71.5%	61.9%
SPORN 01	Sporn 1	Appalachian Power Co.	145	64.7%	49.4%	64.5%	48.6%	70.4%	61.8%
SPORN 02	Sporn 2	Appalachian Power Co.	145	61.9%	44.8%	60.1%	45.9%	67.1%	57.7%
SPORN 03	Sporn 3	Appalachian Power Co.	145	65.4%	46.3%	62.5%	47.3%	62.8%	51.3%
SPORN 04	Sporn 4	Appalachian Power Co.	145	62.6%	45.6%	58.6%	46.1%	67.4%	59.0%
SPORN 05	Sporn 5	Appalachian Power Co.	440	71.4%	59.1%	70.4%	63.6%	69.0%	64.9%
BECKJF6A	Beckjord 6	Columbus Southern Power Co.	52	81.5%	72.9%	84.8%	83.0%	78.7%	68.1%
CONESV01	Conesville 1	Columbus Southern Power Co.	115	21.3%	5.6%	21.9%	10.6%	40.4%	27.8%
CONESV02	Conesville 2	Columbus Southern Power Co.	115	25.2%	7.8%	27.8%	15.4%	44.9%	30.9%
CONESV03	Conesville 3	Columbus Southern Power Co.	165	28.2%	8.9%	29.2%	14.9%	46.7%	36.8%
CONESV4A	Conesville 4	Columbus Southern Power Co.	339	50.8%	29.2%	47.4%	35.0%	67.5%	58.3%
CONESV05	Conesville 5	Columbus Southern Power Co.	400	69.3%	58.6%	72.3%	63.9%	73.9%	70.2%
CONESV06	Conesville 6	Columbus Southern Power Co.	400	70.4%	57.9%	67.4%	59.5%	70.2%	67.5%
PICWAY05	Picway 5	Columbus Southern Power Co.	90	29.0%	9.0%	26.9%	12.0%	41.3%	30.3%
STUART1A	Stuart 1	Columbus Southern Power Co.	152	72.8%	60.1%	76.8%	67.7%	79.0%	74.4%
STUART2A	Stuart 2	Columbus Southern Power Co.	152	77.4%	68.8%	80.2%	77.6%	81.7%	80.7%
STUART3A	Stuart 3	Columbus Southern Power Co.	152	73.0%	59.1%	77.6%	71.6%	79.6%	77.2%
STUART4A	Stuart 4	Columbus Southern Power Co.	152	74.4%	62.7%	78.6%	74.3%	80.8%	79.2%
ZIMMER1A	Zimmer 1	Columbus Southern Power Co.	330	84.0%	80.7%	79.2%	73.5%	80.9%	76.7%
D C CO01	Cook 1	Indiana Michigan Power Co.	1,000	91.1%	91.1%	91.2%	91.2%	91.2%	91.2%
D C CO02	Cook 2	Indiana Michigan Power Co.	1,115	91.2%	91.2%	91.1%	91.1%	91.1%	91.1%
ROCKPO01	Rockport 1	Indiana Michigan Power Co.	1,300	80.9%	75.0%	80.5%	79.3%	81.5%	81.0%
ROCKPO02	Rockport 2	Indiana Michigan Power Co.	1,300	81.9%	74.2%	80.9%	79.1%	82.6%	81.5%
TANNER01	Tanners 1	Indiana Michigan Power Co.	140	48.0%	25.9%	51.9%	40.6%	48.2%	42.2%
TANNER02	Tanners 2	Indiana Michigan Power Co.	140	53.5%	35.8%	53.4%	41.6%	50.7%	44.4%
TANNER03	Tanners 3	Indiana Michigan Power Co.	200	54.6%	37.4%	56.7%	44.7%	50.7%	44.5%
TANNER04	Tanners 4	Indiana Michigan Power Co.	500	82.4%	76.1%	80.7%	78.7%	83.0%	82.0%
BIG SA01	Big Sandy 1	Kentucky Power Co	260	73.6%	62.6%	74.8%	68.3%	76.2%	72.8%
BIG SA02	Big Sandy 2	Kentucky Power Co	800	84.7%	82.3%	84.4%	83.6%	84.6%	84.9%
CARDIN01	Cardinal 1	Ohio Power Co.	585	85.4%	79.4%	76.2%	66.7%	78.6%	71.3%
GAVIN 01	Gavin 1	Ohio Power Co.	1,300	85.9%	85.9%	85.9%	85.9%	85.9%	85.9%
GAVIN 02	Gavin 2	Ohio Power Co.	1,300	85.9%	85.9%	85.9%	85.9%	85.9%	85.9%
KAMMER01	Kammer 1	Ohio Power Co.	200	76.2%	60.8%	81.6%	78.8%	73.2%	64.8%
KAMMER02	Kammer 2	Ohio Power Co.	200	75.8%	58.8%	83.4%	81.4%	69.7%	60.9%
KAMMER03	Kammer 3	Ohio Power Co.	200	75.9%	59.1%	81.7%	78.6%	69.9%	63.1%
MITCHE01	Mitchell 1	Ohio Power Co.	800	43.7%	45.3%	54.9%	36.3%	57.6%	44.2%
MITCHE02	Mitchell 2	Ohio Power Co.	800	44.9%	51.7%	54.8%	43.8%	62.7%	51.8%
MUSKIN01	Muskingum 1	Ohio Power Co.	190	51.5%	23.1%	40.8%	28.5%	57.0%	44.6%
MUSKIN02	Muskingum 2	Ohio Power Co.	190	54.3%	27.8%	44.6%	31.6%	58.6%	47.2%
MUSKIN03	Muskingum 3	Ohio Power Co.	205	48.5%	24.1%	39.9%	27.5%	60.5%	48.6%
MUSKIN04	Muskingum 4	Ohio Power Co.	205	58.9%	34.1%	54.5%	38.3%	64.5%	55.1%
MUSKIN05	Muskingum 5	Ohio Power Co.	575	68.2%	79.9%	84.1%	81.3%	84.9%	84.8%
CLIFTY01	Clifty Creek 1	Ohio Valley Electric Corp	88	78.8%	75.5%	79.8%	78.0%	81.2%	78.2%
CLIFTY02	Clifty Creek 2	Ohio Valley Electric Corp	87	80.7%	77.8%	81.6%	80.1%	82.6%	81.4%
CLIFTY03	Clifty Creek 3	Ohio Valley Electric Corp	88	79.2%	75.1%	80.1%	78.7%	81.3%	78.3%
CLIFTY04	Clifty Creek 4	Ohio Valley Electric Corp	83	79.7%	76.2%	80.4%	78.8%	81.7%	80.3%
CLIFTY05	Clifty Creek 5	Ohio Valley Electric Corp	89	78.1%	72.9%	79.3%	77.5%	80.7%	79.3%
CLIFTY06	Clifty Creek 6	Ohio Valley Electric Corp	82	77.6%	71.6%	78.6%	76.0%	80.2%	78.7%
KYGER 01	Kyger Creek 1	Ohio Valley Electric Corp	89	72.8%	60.7%	75.9%	69.4%	77.3%	75.3%
KYGER 02	Kyger Creek 2	Ohio Valley Electric Corp	83	71.4%	54.4%	74.7%	65.0%	76.3%	72.4%
KYGER 03	Kyger Creek 3	Ohio Valley Electric Corp	86	71.2%	53.5%	75.0%	63.9%	76.8%	71.9%
KYGER 04	Kyger Creek 4	Ohio Valley Electric Corp	84	68.7%	51.7%	73.7%	62.3%	76.0%	69.8%
KYGER 05	Kyger Creek 5	Ohio Valley Electric Corp	84	70.4%	52.6%	73.8%	63.4%	76.2%	70.3%

Source: Cambridge Energy Research Associates

Interpolated Results for 2004–08

Note: Model output for run years 2004, 2006 and 2008 and interpolated values for in-between years (see Tables C.19–C.25).

Table C.19

Change in Interpool Flows with the Removal of Pancaking
(average MW per hour)

	2004	2005	2006	2007	2008
AEP to PJM	563	456	348	302	255
AEP to DVP	195	222	248	218	187
ROMW to PJM	277	251	224	212	199
ROMW to DVP	19	66	113	117	122
Total	**1,055**	**994**	**933**	**848**	**763**

Source: Cambridge Energy Research Associates.

Table C.20

Change in Annual Interpool Energy Flows with the Removal of Pancaking
(GWh)

	2004	2005	2006	2007	2008
AEP to PJM	4,935	3,993	3,050	2,643	2,236
AEP to DVP	1,710	1,941	2,172	1,905	1,639
ROMW to PJM	2,426	2,195	1,964	1,854	1,744
ROMW to DVP	171	579	987	1,026	1,065
Total	**9,242**	**8,707**	**8,173**	**7,428**	**6,684**

Source: Cambridge Energy Research Associates.

Table C.21

Average Regional LMP–Scenario B
(2002$/MWh)

	2004	2005	2006	2007	2008
PJM	25.8	26.1	26.4	27.2	27.9
DVP	29.8	30.5	31.1	32.0	32.8
AEP	18.7	19.2	19.7	20.5	21.2
Rest of Midwest	19.0	19.5	19.9	20.7	21.4

Source: Cambridge Energy Research Associates.

Table C.22

Average Regional LMP–Scenario A
(2002$/MWh)

	2004	2005	2006	2007	2008
PJM	25.2	25.6	26.0	26.8	27.6
DVP	28.8	29.5	30.2	31.1	32.0
AEP	19.8	20.4	20.9	21.7	22.5
Rest of Midwest	19.3	19.9	20.5	21.3	22.1

Source: Cambridge Energy Research Associates.

Table C.23

Change in Average Regional LMP–Scenario A–Scenario B
(2002$/MWh)

	2004	2005	2006	2007	2008
PJM	(0.6)	(0.5)	(0.4)	(0.3)	(0.3)
DVP	(1.0)	(1.0)	(0.9)	(0.8)	(0.8)
AEP	1.1	1.2	1.2	1.3	1.3
Rest of Midwest	0.3	0.4	0.6	0.7	0.7

Source: Cambridge Energy Research Associates.

Table C.24

Decrease in Customer Cost If All Customers Pay LMP: (Scenario A–Scenario B)
(2002$ Million)

	2004	2005	2006	2007	2008
PJM	(162)	(138)	(114)	(110)	(106)
DVP	(83)	(83)	(82)	(82)	(82)
Total	(245)	(220)	(196)	(192)	(187)

Source: Cambridge Energy Research Associates.

Table C.25

Decrease in Customer Cost If All Customers Pay Average Customer Cost: (Scenario A–Scenario B)
(2002$ Million)

	2004	2005	2006	2007	2008
PJM	(40)	(36)	(31)	(32)	(32)
DVP	(32)	(30)	(28)	(24)	(20)
Total	(72)	(66)	(59)	(56)	(52)

Source: Cambridge Energy Research Associates.

Table C.26 provides the change in annual flows into SPP and TVA associated with eliminating AEP wheeling rates. SPP and TVA are net importer for the study period. SPP imports from the north (MAPP) and east (MAIN). TVA is importing mostly from the west (MAIN).

Annual average flows between AEP and TVA are forecast to be small.

The effect of eliminating AEP wheeling rates is small on SPP imports, since SPP is way to the west.

The effect on AEP-TVA flows is also small. With wheeling rates, AEP imports a little from TVA. Without wheeling rates, AEP exports a little.

The effect on VACAR-TVA flows is very small.

If wheeling rates between AEP and TVA had not been eliminated, the apparent benefits of joining PJM would have been slightly greater, because AEP would have had more lower-cost energy to export to the East.

Table C.26

Annual Average Flows Around SPP and TVA

(MW)

Case 1	2004	2006	2008
SPP Net Imports	1,318	1,501	1,532
TVA Net Imports	602	772	316
AEP-TVA	(49)	(71)	(99)
VACAR-TVA	(107)	(106)	(122)
Case 2	2004	2006	2008
SPP Net Imports	1,331	1,539	1,599
TVA Net Imports	630	833	440
AEP-TVA	30	14	(1)
VACAR-TVA	(86)	(87)	(108)
Delta (1 minus 2)	2004	2006	2008
SPP Net Imports	(13)	(38)	(67)
TVA Net Imports	(28)	(61)	(124)
AEP-TVA	(79)	(85)	(98)
VACAR-TVA	(21)	(19)	(14)

Source: Cambridge Energy Research Associates.